APPENDIX A

UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

AMOCO PRODUCTION COMPANY,
APPELLANT

v.

REBECCA W. WATSON, ASSISTANT SECRETARY FOR LAND AND MINERAL MANAGEMENT, ET AL.,
APPELLEES

Nos. 04-5006, 04-5007.

Argued Feb. 14, 2005.
Decided June 10, 2005.

Before: EDWARDS, SENTELLE, and ROBERTS, *Circuit Judges*.

Opinion for the Court filed by *Circuit Judge* ROBERTS.

ROBERTS, *Circuit Judge*: The San Juan Basin covers 7500 square miles in northwest New Mexico and southwest Colorado. Since the end of World War II, it has been a prolific source of natural gas, connected by pipeline to southern California and literally helping to fuel the dramatic growth of that region. Beginning in the 1980s, large-scale extraction of the variety of natural gas known as coalbed methane began to supplement the supply of conventional gas from the region. Coalbed methane contains upwards of ten percent carbon dioxide, which is largely absent from conventional natural gas. Because carbon dioxide does not produce energy, mainline natural

gas pipelines will not accept gas with a carbon dioxide component of more than two to three percent of volume. A high carbon dioxide content does not render the natural gas useless for consumers, but if producers in the San Juan Basin want to sell their gas to markets beyond that sparsely populated region, they must use the mainline and meet its more stringent carbon dioxide standard.

The federal government is a large landowner in the San Juan Basin and, like many other owners of property rich in natural gas, it leases rights to extract the gas in exchange for a percentage of the proceeds. Unlike the case with other landowners, however, the relationship between the government and those who extract gas from the government's land is regulated pursuant to an elaborate array of statutes and rules. The present case involves several disputes between the government and gas producers over how the need to remove the excess carbon dioxide from coalbed methane, to make it palatable to the mainline pipelines, affects the royalty payment the producers owe the government under those statutes and regulations. For the reasons that follow, we affirm the district court's decision and uphold the government's determination that the producers owe additional royalties.

I. Background

Statutory and Regulatory Framework. The Department of the Interior (DOI), through its Minerals Management Service (MMS), issues and administers leases authorizing the extraction of natural gas from government land. The Mineral Leasing Act (MLA), 30 U.S.C. §§ 181 *et seq.* (2000), requires producer-lessees to pay the government-lessor "a royalty at a rate of not less than 12.5 percent in amount or value of the production removed or sold from the lease." *Id.* § 226(b)(1)(a). To ensure the government gets its due in royalties, the Secretary of the Interior is directed by statute to establish a comprehensive inspection, auditing, and collection system. *See id.* § 1711.

In 1988, pursuant to these statutes, MMS "amended and clarified" the rules "governing valuation of gas for royalty computation purposes." Revision of Gas Royalty Valuation Regulations and Related Topics, 53 Fed.Reg. 1230 (Jan. 15, 1988). Under these new regulations, MMS specified that the "value of the production" referred to in 30 U.S.C. § 226(b)(1)(A) must be no less than "the gross proceeds accruing to the lessee for lease production," minus certain allowable deductions. 30 C.F.R. § 206.152(h) (1988). A factor in calculating these "gross proceeds" is a longstanding interpretation of the MLA that obligates lessees to put the gas they extract in "marketable condition at no cost to" the federal lessor. *Id.* § 206.152(i); *see California Co. v. Udall*, 296 F.2d 384, 387-88 (D.C. Cir. 1961) (upholding marketable condition requirement). Under the 1988 regulations, lease products are considered in marketable condition if they "are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." 30 C.F.R. § 206.151. If a lessee sells "unmarketable" gas at a lower cost, the gross proceeds for purposes of royalty calculation must be "increased to the extent that gross proceeds have been reduced because the purchaser, or any other person, is providing certain services" to place the gas in marketable condition. *Id.* § 206.152(i). To take a simple example, if it costs $20 to put gas in marketable condition by removing impurities, and the purified gas is sold for $100, "gross proceeds" for purposes of royalty calculations is $100, regardless of whether the producer removes the impurities and sells the gas for $100, or instead sells the gas for $80 to a purchaser who then removes the impurities.

The regulations allow lessees to deduct from gross proceeds costs directly related to transporting gas from the wellhead for sale at markets remote from the lease. *See id.* § 206.157(a)-(b). The government's generosity with respect to this deduction, however, goes only so far—absent

approval from MMS, a lessee is not allowed to deduct the costs of transporting non-royalty bearing products. *See id.* § 206.157(a)(2)(i), (b)(3)(i). In other words, to the extent the government is not going to share in the proceeds of the producers' distant sale, because some of the product is non-royalty bearing, the government does not in effect share in the cost of transporting that portion of the product by having that cost deducted from "gross proceeds." There is an exception to this logic: a portion of the product may fall into a category known as "waste products which have no value." *Id.* § 206.157(a)(2)(i), (b)(3)(i). Although it may at first seem counterintuitive, the government allows a deduction for the cost of transporting such waste products, because such transport is considered part of the cost of transporting the royalty-bearing product with which the waste products are associated.

Facts and Rulings Below. Producers Amoco Production Company (Amoco) and Atlantic Richfield Company and Vastar Resources, Inc. (ARCO/Vastar) produce coalbed methane on public land in the San Juan Basin pursuant to leases with the federal government. To make the coalbed methane suitable for transportation over mainline pipelines, the producers arranged for the removal of excess carbon dioxide from most of the gas they extracted. Between 1989 and 1996, the producers sold untreated gas at the wellhead to purchasers who would pipe the gas to treatment centers, remove the excess carbon dioxide, and then put the treated gas on the mainline system for transport and sale to end-users throughout the country. The producers' sales arrangements differed; Amoco would sell untreated gas primarily to a wholly-owned trading subsidiary and ARCO/Vastar would contract arms-length sales with unaffiliated purchasers. Nevertheless, the economics of the transactions were the same, with the price of untreated gas at the wellhead reflecting the fact that the purchaser would have to transport the gas to treatment plants and remove the

excess carbon dioxide before sending the gas into the mainline.

On April 22, 1996, MMS issued a letter to lease operators and royalty payors in the San Juan Basin laying out the Service's "guidelines" for calculating royalties on coalbed methane. Payor Letter, at 1. The Payor Letter informed the producers that removing excess carbon dioxide was considered a cost of placing the gas in marketable condition. Consequently, producers who removed the gas themselves could not deduct the cost of doing so from gross proceeds, and those selling untreated gas at a lower price nevertheless needed to add back to gross proceeds the cost of removal services performed by the purchaser. *See id.* at 1-2. The letter also addressed transportation allowances, specifying that producers could deduct the costs of piping the methane and the allowable two to three percent portion of carbon dioxide to the treatment center, but not the cost of transporting the excess carbon dioxide to be removed at the center. In the government's view, that excess constituted a non-royalty bearing product under the regulations. *See id.* at 2-3.

On the heels of the Payor Letter, MMS issued separate orders finding Amoco and ARCO/Vastar deficient in their royalty payments for the period between 1989 and 1996. This shortfall stemmed from the producers' accounting for sales of raw coalbed methane that was later treated and marketed on the mainline by its purchasers. In calculating gross proceeds, the producers did not add back the costs incurred by the purchasers in moving the excess carbon dioxide to the treatment plant and removing it once there. Instead, they calculated gross proceeds the same way they did for sales of coalbed methane used in untreated form by local purchasers. MMS thus concluded that Amoco and ARCO/Vastar owed the government additional royalties totaling $4,117,607 and $782,373, respectively. The producers did not have to add back to gross proceeds the cost of trans-

porting royalty-bearing methane and the allowable three percent carbon dioxide "waste product"—because this cost was deductible in the government's view—and the orders did not assess any additional royalties on sales of gas consumed without treatment.

In separate challenges to these orders before the Assistant Secretary for Land and Minerals Management, the producers argued that untreated gas at the wellhead was already in marketable condition—after all, they sold a fair amount of it in that form, and it was used without treatment—so there was no reason to augment their gross proceeds for royalty calculation purposes. They also argued that the cost of piping the excess carbon dioxide to the treatment plant should be viewed as a deductible transportation cost, not a cost of putting the gas in marketable condition. In the alternative, the producers contended that, under the transportation regulations, the excess carbon dioxide piped to the treatment plants should be regarded as a "waste product." The Assistant Secretary rejected these challenges and also concluded—contrary to the producers' contentions—that the Payor Letter was not a rule, and so was not subject to the Administrative Procedure Act's notice and comment requirement. *See* 5 U.S.C. § 553. The Assistant Secretary also rejected the producers' argument that collection of the royalties was barred by the six-year statute of limitations for government actions for money damages found in 28 U.S.C. § 2415.

In the District Court for the District of Columbia, the producers sought a declaratory judgment and injunction against enforcement of the MMS orders. On cross-motions for summary judgment, the district court ruled for the government. *See Amoco Production Co. v. Baca*, 300 F. Supp. 2d 1 (D.D.C.2003). Amoco and ARCO/Vastar appeal.

II.

We review the district court decision *de novo*, *Fina Oil & Chem. Co. v. Norton*, 332 F.3d 672, 675-76 (D.C. Cir. 2003), and will reverse the Assistant Secretary's rulings only if they are "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law," or if they are "in excess of statutory jurisdiction, authority, or limitations, or short of statutory right." 5 U.S.C. § 706(2)(A), (C); *Gerber v. Norton*, 294 F.3d 173, 178 (D.C. Cir. 2002).

A. We first turn to the producers' argument that the Assistant Secretary's application of the marketable condition rule violates the MLA. The Assistant Secretary concluded that "the value for royalty purposes must be determined by adding to the gross proceeds received from the wellhead purchaser the cost of treating the gas . . . to the level required to place the gas in marketable condition." MMS Decision of Sept. 12, 2000 (Amoco Decision) at 10 [J.A. 11]; MMS Decision of Mar. 24, 2000 (ARCO/Vastar Decision) at 6. The producers contend this conclusion cannot be squared with the statutory provision requiring producers to pay royalties based on the "amount or value of the production removed or sold *from the lease*." 30 U.S.C. § 226(b)(1)(A) (emphasis added). The producers read the underscored phrase as requiring that the physical leasehold be treated as the relevant geographic market, precluding calculation of royalties based on gross proceeds derived from sales remote from the wellhead.

We review the agency's interpretation of the MLA, a statute DOI administers, within the framework of *Chevron, U.S.A., Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837, 104 S.Ct. 2778, 81 L. Ed. 2d 694 (1984). *See Indep. Petroleum Ass'n of Am. v. DeWitt*, 279 F.3d 1036, 1039-40 (D.C. Cir. 2002) ("*IPAA*"). Under the first step of *Chevron*, we inquire whether Congress has spoken directly to the question at issue. 487 U.S. at 842, 108 S.Ct. 2687. If so, we give effect to that clearly expressed intent. If instead the

statute is "silent or ambiguous with respect to the specific issue," we defer to the agency interpretation, so long as it is reasonable. *Id.* at 842-43, 108 S.Ct. 2687.

Although the producers present a textually plausible reading of section 226, theirs is not the only one available. The phrase "from the lease" is sufficiently broad to be read as referring simply to the origin of the gas. Gas that is "from the lease" and that is marketed at a remote location can readily be described as gas "removed or sold from the lease." The producers read the statute as if it referred to gas "sold *at* the lease," but that is not the case. They direct us to no precedent limiting marketable condition to their narrowing construction. Although they observe that this court in *California Co.* applied the marketable condition rule to sales of treated gas near the wellhead, that is of little help to them; *all* the gas at issue there "was conditioned by the seller and delivered to the purchaser within a short distance of the wells," 296 F.2d at 387, so the question presented here did not arise.

The producers' reliance on our more recent decision in *IPAA* is also misplaced. They direct to us to a portion of the opinion observing that DOI "abide[s] by the statutory mandate to base royalty on the 'value of the production removed or sold from the lease,'" 279 F.3d at 1037 (quoting 30 U.S.C. § 226(b)(1)(A)), but the cited dictum does not even interpret "from the lease," let alone do so authoritatively. If anything, *IPAA* was skeptical of the producers' "almost metaphysical" proposition "that the sale of 'marketable condition' gas at the leasehold represent[ed] a baseline" beyond which the government had to share any costs incurred further down the line. *Id.* at 1041.

Because the Assistant Secretary has not interpreted the statute in a manner contrary to clear congressional intent, the next step is to ask whether her construction is a reasonable one. *See Chevron*, 467 U.S. at 843, 104 S.Ct. 2778. The producers do not, however, appear to marshal a step two ar-

gument. Consequently, we have no basis for finding the Assistant Secretary's interpretation unreasonable. *See Consumer Elec. Ass'n v. FCC*, 347 F.3d 291, 299 (D.C. Cir. 2003).

B. The producers also contend that the Assistant Secretary acted arbitrarily and capriciously by misinterpreting the MLA regulations and departing from agency precedent. Although we will not allow an agency to "rewrit[e] regulations under the guise of interpreting them," *Fina Oil*, 332 F.3d at 676, we nevertheless owe "substantial deference to an agency's interpretation of its own regulations," giving that interpretation "controlling weight unless it is plainly erroneous or inconsistent with the regulation," *Thomas Jefferson Univ. v. Shalala*, 512 U.S. 504, 512, 114 S.Ct. 2381, 129 L. Ed. 2d 405 (1994) (internal quotation marks omitted). Such deference is particularly appropriate in the context of "'a complex and highly technical regulatory program,' in which the identification and classification of relevant 'criteria necessarily require significant expertise and entail the exercise of judgment grounded in policy concerns.'" *Id.* (quoting *Pauley v. BethEnergy Mines, Inc.*, 501 U.S. 680, 697, 111 S.Ct. 2524, 115 L. Ed. 2d 604 (1991)).

The producers argue that the DOI regulation defining gas in "marketable condition" as gas acceptable to "a purchaser under a sales contract typical for the field or area," 30 C.F.R. § 206.151, requires MMS to consider untreated gas sold at the wellhead to be in marketable condition, notwithstanding any later off-lease treatment. The Assistant Secretary concluded, however, that because the "dominant market for gas from the area is for gas that is utilized in distant markets with a much lower CO_2 content," sales contracts for *treated* gas were typical for the area, while those for untreated gas were not. Amoco Decision at 7; *see also* ARCO/Vastar Decision at 5. Although the producers concede that most of the gas purchased at their leaseholds is treated for use in downstream markets, they argue that

the Assistant Secretary's "dominant end-use" rationale is irreconcilable with the text of section 206.151 of the regulations, which frames typicality in terms of a given "field or area."

We are not persuaded, however, that the regulations require MMS to understand typical sales contracts—and thus marketable condition—as relating to transactions at the leasehold or immediately nearby. As an initial matter, it is not even clear that "field or area"—the textual hook for the producers' interpretation—refers only to leasehold land. The regulations define "area" as "a geographic region *at least as large* as the defined limits of [a] gas field, in which . . . gas lease products have similar quality, economic, and legal characteristics," and define "field" as "a geographic region situated over one or more subsurface . . . gas reservoirs encompassing *at least* the outer-most boundaries of all . . . gas accumulations." 30 C.F.R. § 206.151 (emphases added). Because these terms do not foreclose the possibility of defining a region beyond the geographical limits of a leasehold, we are hesitant to conclude that the Assistant Secretary's interpretation failed to "sensibly conform[ ] to the purpose and wording of the regulations." *Martin v. Occupational Safety and Health Review Comm'n*, 499 U.S. 144, 151, 111 S.Ct. 1171, 113 L. Ed. 2d 117 (1991) (internal quotation marks omitted).

The producers' construction also does not square with the regulatory scheme as a whole. The regulation stipulating that producers are to place gas in marketable condition at no cost to the government does not contain a geographic limit. *See* 30 C.F.R. § 206.152(i). More importantly, regulations governing transportation allowances obviously assume that valuation of gas "at a point (e.g., sales point or point of value determination) off the lease" is permissible. *Id.* § 206.156(a). The Assistant Secretary's approach to the marketable condition rule is entirely consistent with this regulatory scheme and the basic principle that the MLA

contemplates a meaningful distinction between marketing and merely selling gas. *See California Co.*, 296 F.2d at 388.

The Assistant Secretary's approach to marketable condition should not have surprised the producers. When soliciting comments for the 1988 rulemaking that led to reiteration of the marketable condition rule in regulation 206.152, the agency entertained suggestions from producers that the government lessor should share treatment costs, by allowing producers to deduct all post-production costs under the theory that royalties are "due on the market value of production at the lease or well." 53 Fed.Reg. at 1252. Otherwise, industry commentators argued, MMS would "improperly sweep[ ] all post-production operations under the holding of [*California Co.*]." *Id.* MMS considered but rejected this suggestion, concluding that "so-called post-production costs . . . [g]enerally . . . are not allowed as a deduction because they are necessary to make production marketable." *Id.* at 1253.

The producers alternatively contend that, because there is an established demand for untreated gas, sales of such gas at the wellhead should be treated as "typical" for defining marketable condition. It is true that fifteen to twenty percent of the gas purchased from the producers was consumed locally, and it is plausible to conclude that contracts for one-fifth of a product are common enough to be "typical." But it is just as plausible to read typicality as embracing the *most* common use and sale of gas from the area, and it is not at all obvious from the text and purposes of the regulations that contracts for one-fifth of the gas should govern the regulatory treatment of the remaining eighty percent.

Finally, we disagree with the producers' argument that the Assistant Secretary impermissibly departed from agency precedent. In *Xeno, Inc.*, the agency concluded gas was in marketable condition at the wellhead based on evidence of competing purchase offers there. 134 I.B.L.A. 172,

180-84 (1975). Central to *Xeno*, however, was the fact that the gas was suitable for pipeline access *before* gathering and compression, a quality reflected in its price at the wellhead. *See id.; see also Amerada Hess Corp. v. Dep't of Interior*, 170 F.3d 1032, 1037 (10th Cir. 1999) (distinguishing Xeno when a producer had not shown gas was in marketable condition at the wellhead).

Nor is *Beartooth Oil & Gas Co. v. Lujan*, No. 92-99 (D. Mont. Sept. 22, 1993), to the contrary. *Beartooth* overruled a decision that, in assessing royalties on wellhead sales, included the value of subsequent compression and delivery by a purchaser. Even if this unpublished district court opinion—withdrawn after a settlement—bound MMS, it is readily distinguishable. The *Beartooth* court ruled for the producer not because the court was certain the gas was in marketable condition at the wellhead, but rather because the agency did not make findings supporting the assertion that the gas was not. *See Beartooth* at 9-10. Here, the Assistant Secretary explained in detail why the gas was not in marketable condition at the wellhead. *See* Amoco Decision at 9-11; ARCO/Vastar Decision at 6-7.

III.

The Assistant Secretary allowed the producers to deduct from gross proceeds the costs of transporting the royalty-bearing methane and the three percent carbon dioxide "waste product" to the treatment plant, but not the costs of transporting and removing the excess carbon dioxide. The producers argue that some or all of the costs of ridding the gas of excess carbon dioxide should be deductible from gross proceeds as a cost of transporting the gas to market under 30 C.F.R. § 206.157(a)-(b).

To argue that all the extra costs are deductible, the producers liken these expenses to "firm demand" charges—nonrefundable deposit payments required to reserve pipeline capacity. DOI argued that such charges were not rela-

ted to transportation in *IPAA*, but we did not accept DOI's argument. *See* 279 F.3d at 1042 ("While some reason may lurk behind the government's position, it has offered none, and we have no basis for sustaining its conclusion."). The producers contend that, like firm demand charges, the costs at issue here are necessary to secure access to a mainline system that will not accept gas with a carbon dioxide content of more than two or three percent. In support of their argument, they also cite two other cases purportedly regarding pre-pipeline treatment as a transportation cost: *Exxon Corp.*, 118 I.B.L.A. 221 (1991) and *Marathon Oil Co. v. United States*, 604 F. Supp. 1375 (D. Alaska 1985).

Unlike the case in *IPAA*, however, here the Assistant Secretary has explained why the costs at issue are not properly considered transportation costs: because removal of the excess carbon dioxide was necessary to place the gas in marketable condition, those same costs could not be part of the transportation allowance. The logic of the regulations bars an expenditure to place gas in marketable condition from also being an expenditure deductible from gross proceeds as a transportation cost. *See* 30 C.F.R. § 206.152(i) (lessees must "place gas in marketable condition at no cost to the Federal Government"). Because we uphold the Assistant Secretary's conclusion that these costs are necessary to place the gas in marketable condition, we cannot quarrel with her rejection of the producers' transportation theory. Unsurprisingly, none of the cases the producers cite deals with deducting costs necessary for placing gas in marketable condition. The firm demand charges to reserve space on the pipeline at issue in *IPAA*, for example, related solely to transportation and had nothing to do with conditioning the gas for market. *See IPAA*, 279 F.3d at 1042; *see also Marathon Oil*, 604 F. Supp. at 1386 (costs of liquefying natural gas deductible because done "for purposes of storage or shipment" and end-product "chemically identical to the natural gas at the lease"); *Exxon Co.*, 118 I.B.L.A. at

242 (deductible dehydration of gas "was not performed to satisfy market specifications").

Seeking at least half a loaf, the producers argue the Assistant Secretary erred in treating the excess carbon dioxide (the amount beyond the pipeline threshold) as a non-royalty-bearing product, whose transportation cost is nondeductible. The producers contend that the carbon dioxide in excess of the pipeline tolerance should have been treated the same as that within the tolerance—as a waste product—with the result that the deductible transportation cost would not be reduced by the cost of transporting any of the carbon dioxide.

Although carbon dioxide is carbon dioxide, there is a meaningful distinction in the regulation between the amount that may be marketed along with the gas, and the excess that must be removed to make the gas marketable. The two *amounts* need not be treated the same under the rules, simply because they are the same *product*. Within the pipeline tolerance, carbon dioxide is a waste product because it need not be removed to place the gas in marketable condition; beyond the tolerance, the carbon dioxide is a non-royalty-bearing product that must be removed for the gas to considered marketable under the rules. This difference has the consequence ascribed by the Secretary when it comes to determining the deductibility of transportation costs.

The producers rely on an illustrative example in the MMS-issued Payor Handbook that treats carbon dioxide in a manner suggesting it is waste. This example—which does not purport to be a rule and concerns a carbon dioxide content of only one percent, *see* 3 MINERALS MGMT. SERV., U.S. DEP'T OF THE INTERIOR, OIL & GAS PAYOR HANDBOOK § 6.4.1 (1993)—hardly compels the agency to treat a ten percent component of carbon dioxide as waste, let alone creates an inference that carbon dioxide is always waste.

IV.

The producers also challenge the Payor Letter cited in the orders and in the Assistant Secretary's decisions, arguing that it constituted a new rule the agency could promulgate only through notice and comment rulemaking. *See* 5 U.S.C. § 551(4) (defining a rule as "the whole or part of an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy or describing the organization, procedure or practice requirements of an agency"). Rejecting the Assistant Secretary's explanation that the Payor Letter was merely an interpretation of existing regulations, the producers ask us to set it aside and consider the Assistant Secretary's reliance upon it unlawful because the agency did not promulgate the rule as required by the Administrative Procedure Act. *See id.* § 553(b)(3)(A).

This challenge is governed by *Indep. Petroleum Ass'n of Am. v. Babbitt*, which held that a similar MMS letter was not a rule subject to the notice and comment requirement. 92 F.3d 1248, 1256-57 (D.C. Cir. 1996). As in *Babbitt*, the Payor Letter here is not an agency statement with future effect because nothing under DOI regulations vests the Letter's author—in *Babbitt* and this case MMS's Associate Director for Royalty Management—with the authority to announce rules binding on DOI. *Id.* at 1256. "The letter is not an agency rule at all, legislative *or* otherwise, because it does not purport to, nor is it capable of, binding the agency." *Id.* at 1257.

The producers attempt to distinguish *Babbitt* by alleging that here the agency adopted the Payor Letter's positions when it issued and affirmed the orders. But nothing in the decisions under review suggests that the agency viewed the Payor Letter as authoritative or binding; the agency in those decisions applied the pertinent statutes and regulations with no determinative reliance on the Payor Letter. The agency decisions reached the same result as the gui-

dance in the Payor Letter, but that was true in *Babbitt* as well. The sort of "workaday advice letter[s] that agencies prepare countless times per year in dealing with the regulated community," *Indep. Equip. Dealers Ass'n v. EPA*, 372 F.3d 420, 427 (D.C. Cir. 2004) (internal quotation marks omitted), do not retroactively become agency rules whenever they are referenced in an agency decision.

V.

Finally, the producers argue that the district court and the Assistant Secretary erred in concluding that the MMS orders assessing additional royalties were not barred by the statute of limitations found at 28 U.S.C. § 2415(a).[1] That provision specifies that

> [E]very action for money damages brought by the United States or an officer or agency thereof which is founded upon any contract express or implied in law or fact, shall be barred unless the complaint is filed within six years after the right of action accrues or within one year after final decisions have been rendered in applicable administrative proceedings required by contract or by law, whichever is later.

The threshold question is whether an administrative order assessing additional royalties can reasonably be understood to be an "action for money damages" initiated by the filing of a "complaint." The phrase "action for money damages" points strongly to a suit in a court of law, rather than an agency enforcement order that happens to concern money due under a statutory scheme. *See* BLACK'S LAW DIC-

---

[1] The dispute about the applicability of 28 U.S.C. § 2415(a) to demands for additional royalties is no longer a live one with respect to production after September 1, 1996, for which Congress has set a seven-year limitations period. *See* Federal Oil and Gas Royalty Simplification and Fairness Act of 1996, Pub.L. No. 104-185, 110 Stat. 1700 (codified at 30 U.S.C. § 1724).

TIONARY 389 (6th ed. 1990) (defining "damages" as "pecuniary compensation or indemnity, which may be recovered in the courts"); *OXY USA, Inc. v. Babbitt*, 268 F.3d 1001, 1010 (10th Cir. 2001) (en banc) (Briscoe, J., dissenting) ("Taken together, the entire phrase plainly and indisputably refers to lawsuits brought by the federal government seeking compensatory relief for losses suffered by the government.").

Any doubt is removed by the fact that subsection 2415(a) measures the limitations period from the filing of a "complaint." It strains legal language to construe this administrative compliance order as a "complaint" for money damages in any ordinary sense of the term. *See* BLACK'S LAW DICTIONARY 285 (6th ed. 1990) (defining complaint as an "initial pleading" under "codes or Rules of Civil Procedure" that contains, *inter alia*, a "statement of the grounds upon which the *court's* jurisdiction depends") (emphasis added). Although some statutes provide for a "complaint" that triggers administrative proceedings, *see, e.g.*, 5 U.S.C. § 1215(a)(1); 15 U.S.C. §§ 45(b), 522; 25 U.S.C. § 2713(a)(3); 29 U.S.C. § 160(b), adjudicative hearings on the merits follow such filings. Here MMS issued an *order*, the defiance of which incurs a "Notice of Noncompliance" and subsequent civil penalties, absent a successful appeal. *See* 30 C.F.R. § 241.51 (1996); *see also* BLACK'S LAW DICTIONARY 1096 (6th ed. 1990) (defining order as "[a] mandate; precept; command or direction authoritatively given; rule or regulation").

While we are satisfied from the text of subsection 2415(a) that the agency action at issue here does not fall under the clause's purview, the statute as a whole is admittedly less clear. One of the statute's enumerated exceptions—added more than 16 years after the passage of the original Act, *see* Debt Collection Act of 1982, Pub.L. No. 97-365, § 9, 96 Stat. 1749, 1754—states that "[t]he provisions of this section shall not prevent the United States or an officer or agency thereof from collecting any claim of the United States by

means of administrative offset, in accordance with section 3716 of title 31." 28 U.S.C. § 2415(i). The producers contend that subsection 2415(a) must apply to administrative proceedings generally, or there would have been no need to except administrative offsets in subsection (i).

This argument is not without force. It is a familiar canon of statutory construction that, "if possible," we are to construe a statute so as to give effect to "every clause and word," *United States v. Menasche*, 348 U.S. 528, 538-39, 75 S.Ct. 513, 99 L.Ed. 615 (1955) (internal quotation marks omitted), and the producers' argument has helped convince two other circuits that subsection 2415(a) can apply to other administrative proceedings, *see OXY USA*, 268 F.3d at 1006; *United States v. Hanover Ins. Co.*, 82 F.3d 1052, 1055 (Fed. Cir. 1996). In this case, however, the inference to be drawn from the addition of subsection 2415(i) does not dissuade us from the more natural reading of the express language of subsection 2415(a). As the Supreme Court recently explained, "our preference for avoiding surplusage constructions is not absolute." *Lamie v. U.S. Trustee*, 540 U.S. 526, 124 S.Ct. 1023, 1031, 157 L. Ed. 2d 1024 (2004). *See Chickasaw Nation v. United States*, 534 U.S. 84, 89, 122 S.Ct. 528, 151 L. Ed. 2d 474 (2001) (adopting construction that leads to surplusage because "we can find no other reasonable reading of the statute"). No canon of construction justifies construing the actual statutory language beyond what the terms can reasonably bear. *See Conn. Nat'l Bank v. Germain*, 503 U.S. 249, 252-53, 112 S.Ct. 1146, 117 L. Ed. 2d 391 (1992).

The context surrounding the passage of subsection 2415(i) gives us some comfort that the provision is not so much surplusage as the result of a congressional effort to moot a debate between the Justice Department and the Comptroller General about the reach of subsection 2415(a) in the context of administrative offsets. The Justice Department thought subsection 2415(a) might be invoked to

bar administrative offsets; the Comptroller General concluded that it was not applicable in that context. The Comptroller General nevertheless recommended that Congress enact subsection 2415(i) "as a means of resolving the differences between us." *Debt Collection Act of 1981: Hearings on S.1249 before the Senate Commitiee on Governmental Affairs*, 97th Cong. 83 (1981) (statement of Milton J. Socolar, Acting Comptroller General). "By adopting section 2415(i), Congress thus did not have to decide whether the Department of Justice or the Comptroller General had the better of the argument as to the proper construction of the pre-1982 version of section 2415." *Hanover Ins. Co.*, 82 F.3d at 1057 (Bryson, J., dissenting). We think it clear that subsection 2415(a), by its terms, does not cover administrative actions, and the fact that Congress "sought to make [the] statute crystal clear rather than just clear" in the context of administrative offsets does not alter our conclusion. *In re Collins*, 170 F.3d 512, 513 (5th Cir. 1999).

Finally, buttressing our conclusion not to let subsection 2415(i) alter the clear import of 2415(a) is the opposing canon (there always seems to be one) that statutes of limitations against the sovereign are to be strictly construed. *See E.I. du Pont de Nemours & Co. v. Davis*, 264 U.S. 456, 462, 44 S.Ct. 364, 68 L.Ed. 788 (1924); *Hanover Ins. Co.*, 82 F.3d at 1057 (Bryson, J., dissenting). Expanding the apparent scope of a statute of limitations beyond its plain language by inference from an express exception is hardly strict construction. Similar concerns helped dissuade the Supreme Court from relying on the surplusage canon in *Chickasaw Nation*. *See* 534 U.S. at 90, 122 S.Ct. 528 (application of surplusage canon would contravene rule that Congress ordinarily enacts tax exemptions explicitly).

Although other courts addressing this question have emphasized the underlying purpose of repose animating section 2415, *see OXY USA*, 268 F.3d at 1005-06; *Hanover Ins. Co.*, 82 F.3d at 1055, the Supreme Court has frequently

warned that such appeals to purpose cannot override a statute's clear language, *see, e.g., Badaracco v. Comm'r of Internal Revenue*, 464 U.S. 386, 398, 104 S.Ct. 756, 78 L. Ed. 2d 549 (1984) ("Courts are not authorized to rewrite a statute because they might deem its effects susceptible of improvement. This is especially so when courts construe a statute of limitations, which must receive a strict construction in favor of the Government.") (internal quotation marks and citation omitted). Consequently, we join the Fifth Circuit, *see Phillips Petroleum Co. v. Johnson*, No. 93-1377, 1994 WL 484506 (5th Cir. Sept 7, 1994), in concluding that the statute of limitations in subsection 2415(a) does not apply to bar an administrative order demanding payment owed pursuant to the MLA and its regulations.

Because we conclude that the government's demand for additional royalties is not an action for money damages initiated by the filing of a complaint, we do not need to address the government's further arguments that the demand neither seeks "money damages" nor is "founded upon a contract." 28 U.S.C. § 2415(a).

The judgment of the district court is

Affirmed.

APPENDIX B

UNITED STATES DISTRICT COURT, DISTRICT OF COLUMBIA

AMOCO PRODUCTION COMPANY,
PLAINTIFF,

v.

SYLVIA V. BACA, ET AL.,
DEFENDANTS.

VASTAR RESOURCES, INC. AND ATLANTIC RICHFIELD COMPANY,
PLAINTIFFS,

v.

SYLVIA V. BACA, ET AL.,
DEFENDANTS.

Nos. CIV.A. 00-02933 (WBB),
CIV.A. 00-01480 (WBB)

Nov. 14, 2003.

MEMORANDUM

BRYANT, Senior District Judge.

Plaintiffs, Amoco Production Company ("Amoco") and Atlantic Richfield Company and Vastar Resources ("ARCO/Vastar"), individually filed complaints seeking a declaratory judgment and injunction against Defendants, the United States Department of the Interior ("DOI"), its Secretary

Bruce Babbit, and its Assistant Secretary Sylvia Baca.[1] Plaintiffs seek to enjoin DOI decisions relating to the determination of royalties due on the production of coalbed methane gas produced by Plaintiffs from certain federal leases.

Currently before the Court are the parties' Motions for Summary Judgment. Plaintiffs ask the Court to declare the DOI decisions invalid and unlawful and to enjoin the DOI from implementing or enforcing its decisions. Defendants oppose Plaintiffs' motions and argue that they are entitled to judgment as a matter of law. Also before the Court is an amicus brief filed by the Southern Ute Indian Tribe ("Tribe") in support of Defendants.

BACKGROUND

Plaintiffs, Amoco and ARCO/Vastar produce coalbed methane gas as lessees under federal oil and gas mineral leases in the San Juan Basin of northwestern New Mexico. The Minerals Leasing Act ("MLA") governs the terms of federal oil and gas leases, including the leases involved in this case. 30 U.S.C. §§ 181-287 (2003). The MLA was intended by Congress to "promote wise development of [ ] natural resources and to obtain for the public a reasonable financial return on assets that 'belong' to the public." *California Co. v. Udall*, 296 F.2d 384, 388 (D.C. Cir. 1961). In return for the privilege of producing coalbed methane gas on federal land, the MLA requires lessees to pay royalties based on the value of the production.

Coalbed methane gas, such as that produced by Plaintiffs, differs from conventional natural gas in that it contains significantly higher levels of carbon dioxide (CO_2). CO_2 reduces the value per unit of volume of natural gas because it has no energy value. As a result, CO_2 is generally

---

[1] After taking office, Secretary Gale Norton was substituted for Bruce Babbit and Assistant Secretary Wallace P. deWitt was substituted for Sylvia V. Baca.

removed from the gas after it is extracted and gas transportation pipelines typically have quality specifications limiting the amount of CO_2 allowed in the gas stream. In some instances, CO_2 is recovered after removal and sold as a separate product, however that is not the case here.

On April 22, 1996, the Associate Director for Royalty Management, MMS, issued a letter to producers of coalbed methane gas ("Dear Operator Letter") containing guidelines for calculating the proper payment of royalties and correct reporting of production. The letter responded to questions received by MMS from producers operating in the vicinity of New Mexico's San Juan Basin, a group of producers that includes Plaintiffs. The guidelines contained in the Dear Operator Letter apply specifically to circumstances in which CO_2 is removed from coalbed methane gas and vented into the air rather than being processed and sold as a separate product.

The Dear Operator Letter echoed internal guidelines contained in a December 7, 1995 MMS memorandum ("December Memorandum") that also addressed the valuation of coalbed methane gas production. The December Memorandum in turn was issued following a November 2, 1995 meeting of the MMS Royalty Policy Board during which interested parties, including producers, offered alternative valuation and reporting methods for coalbed methane. The valuation policy set forth in the December Memorandum was a modified version of that presented by the MMS and the State of New Mexico during the November meeting.

On May 22, 1996, ARCO/Vastar appealed the guidelines contained in the Dear Operator Letter, but the appeal was returned because the letter itself was not a final decision of the MMS Director. MMS advised ARCO/Vastar that an appeal would be appropriate in the event lessees were ordered to take action to correct any noncompliance with the letter's guidelines. Subsequently, the State of New Mexico audited both Plaintiffs' production and royalty reporting and deter-

mined that, in fact, ARCO/Vastar and Amoco were not in compliance with the guidelines contained in the Dear Operator Letter. Based on the results of the New Mexico audit, the MMS issued the decision and orders that form the basis of Plaintiffs' Complaints.

ARCO/Vastar's Complaint

ARCO/Vastar appeals the consolidated decision of Assistant Secretary Sylvia V. Baca issued on March 24, 2000 ("ARCO/Vastar Decision"), which largely affirmed two decisions of the MMS relating to the calculation of royalties due on the sale of coalbed methane gas produced from federal leases held by ARCO/Vastar. The first decision was an MMS order issued on January 22, 1997 ("January Order") finding that ARCO/Vastar incorrectly calculated the royalties due on sales between 1989 and 1996. Upon review of deductions allowable under applicable regulations and the guidelines contained in the December Memorandum, the MMS determined that ARCO/Vastar erroneously took deductions for certain transportation and processing costs related to the transportation and removal of CO_2. As a result, the January Order directed ARCO/Vastar to pay past due royalties of $782,373, to recalculate the royalties due on certain leases in the San Juan Basin during the audit period, and to pay any additional royalties found to be due. The January Order further stated that late payment interest would be calculated and assessed pursuant to 30 C.F.R. § 218.102 (1996) upon receipt of any additional royalties due.

The second decision addressed by the ARCO/Vastar Decision was a decision by the MMS Royalty Valuation Board ("RVD Decision") issued on July 14, 1997 which denied a request for an extraordinary processing cost allowance. ARCO/Vastar had requested approval for an extraordinary processing cost allowance for the costs of removing CO_2 from coalbed methane gas produced from a federal lease and treated at a particular treatment facility. Based on

applicable regulations, the December Memorandum and the Dear Operator Letter, the Royalty Valuation Board rejected ARCO/Vastar's argument that the composition of the gas stream, plant design and associated costs justified the requested allowance.

Because the January Order and the RVD Decision raised overlapping issues related to the definition of marketable condition and extraordinary processing costs, the Assistant Secretary consolidated ARCO/Vastar's appeals of the two decisions. The ARCO/Vastar Decision largely upheld both the January Order and the RVD Decision and addressed four issues: (1) whether the cost of CO_2 removal is necessary to place the gas in marketable condition or allowable as an extraordinary processing cost allowance; (2) whether costs incurred to transport the coalbed methane gas are deductible; (3) whether the April 22, 1996 Dear Operator Letter violates the Administrative Procedure Act; and, (4) whether late payment interest is applicable to royalties deemed deficient for prior periods.

Amoco's Complaint

Amoco appeals the Assistant Secretary's decision of September 12, 2000 ("Amoco Decision"), which denied (with slight modifications) Amoco's appeal of a May 27, 2000 MMS Order ("May Order") directing Amoco to pay additional royalties of $4,117,607, to conduct a restructured accounting of certain federal and Indian leases, and to pay any additional royalties found to be due. The Assistant Secretary addressed four issues in the Amoco Decision: (1) whether CO_2 removal is necessary to place the gas at issue in marketable condition; (2) whether the costs of transporting excess CO_2 is deductible when coalbed gas is treated away from the lease; (3) whether the April 22, 1996 Dear Operator Letter violates the Administrative Procedure Act; and, (4) whether MMS can collect royalties that

become due more than six years before the date of the order to pay.

Since ARCO/Vastar and Amoco's appeals raise common issues their Motions for Summary Judgment were consolidated for briefing purposes. Plaintiffs argue that the guidelines contained in the Dear Operator Letter are invalid because the letter violates the Administrative Procedure Act. They further argue that CO_2 removal is not necessary to place coalbed methane gas in marketable condition and that they are entitled to transportation allowances for transporting CO_2 from the wellhead to treatment facilities where CO_2 is removed. Plaintiffs additionally assert separate claims. ARCO/Vastar argues that it is entitled to an allowance for extraordinary processing costs and that DOI improperly assessed late payment interest on overdue royalties. Amoco argues that the statute of limitations prohibits the collection of royalties after six years. The Court will first address Plaintiffs' common claims and then move to the individual claims.

APPLICABLE LAW

Summary Judgment Standard and Standard of Review

Summary judgment is appropriate when the record shows that "there is no genuine issue as to any material fact and that the moving party is entitled to judgment as a matter of law." Fed. R. Civ. Pro. 56(c) (2003). The Court must set aside the Assistant Secretary's decisions under the Administrative Procedure Act ("APA") if they are "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with the law." 5 U.S.C. 706(2)(A) (1996). When Congress has not spoken to the specific question at issue a court will defer to an agency's interpretation of a statute it is entrusted to administer so long as [is] reasonable and "is based on a permissible construction of the statute." *Chevron U.S.A., Inc. v. Natural Resources Defense Council*, 467 U.S. 837, 842-45, 104 S.Ct. 2778, 81 L. Ed. 2d 694 (1984).

Deference to the Assistant Secretary's decisions is appropriate in this case because Congress plainly delegated broad authority to the DOI "'to prescribe necessary and proper rules and regulations and to do any and all things necessary to carry out and accomplish the purposes of [the Minerals Leasing Act]' . . . [which includes] collecting royalties and determining the methods by which they are calculated." *Independent Petroleum Ass'n of America v. DeWitt*, 279 F.3d 1036, 1039 (D.C. Cir. 2002) ("*IPAA*") (quoting 30 U.S.C. § 189). Moreover, deference is regularly accorded to agency decisions relating to mineral leases and royalty valuations. *IPAA*, 279 F.3d at 1040 (citing numerous cases in which courts deferred to agency construction of royalty regulations).[2]

The Mineral Leasing Act, the Federal Oil and Gas Royalty Management Act and Related Regulations

The MLA invests the Secretary of the Department of the Interior with the authority to "prescribe necessary and proper rules and regulations and to do any and all things necessary to carry out and accomplish the purposes of [the MLA]." 30 U.S.C. § 189 (1986). The Minerals Management Services ("MMS"), a division within the DOI, administers the MLA and manages royalty payments.

---

[2] As this Circuit has noted, arbitrary and capricious review under the APA and the *Chevron* deference standard of review "overlap at the margins." *Independent Petroleum Ass'n of America v. Babbitt*, 92 F.3d 1248, 1258 (D.C. Cir. 1996) ("*Babbitt*"); *Arent v. Shalala*, 70 F.3d 610, 615 (D.C. Cir. 1995); *Nat'l Ass'n of Regulatory Util. Comm'rs v. ICC*, 41 F.3d 721, 728 (D.C. Cir. 1994). The heart of the matter in this case is whether the Assistant Secretary's decisions interpreting royalty valuation statutes and regulations were reasonable and consistent with the purpose of the Mineral Leasing Act. Understanding that an unreasonable interpretation is functionally equivalent to an arbitrary or capricious interpretation, analytically, the Court will apply the *Chevron* deference standard of review.

The Federal Oil and Gas Royalty Management Act of 1982 ("FOGRMA") was enacted by Congress upon finding that "the system of accounting with respect to royalties and other payments due and owing on oil and gas produced from such lease sites is archaic and inadequate." 30 U.S.C. § 1701(a)(2) (1986). The purpose of FOGRMA is to:

> clarify, reaffirm, expand, and define the responsibilities and obligations of lessees, operators, and other persons involved in transportation or sale of oil and gas from the Federal and Indian lands . . . [and] to clarify, reaffirm, expand, and define the authorities and responsibilities of the Secretary of the Interior to implement and maintain a royalty management system for oil and gas leases on Federal lands . . . .

30 U.S.C. § 1701(b)(1), (2) (1986).

FOGRMA directs the Secretary of DOI to "audit and reconcile, to the extent practicable, all current and past lease accounts for leases of oil or gas and take appropriate actions to make additional collections or refunds as warranted." *Id.* at § 1711(c)(1) (1986). The Secretary may delegate all or part of this authority to a State upon written request. *See* 30 U.S.C. § 1735(a) (2003).

As noted previously, the MLA requires federal lessees to pay royalties in return for the privilege of mining federal lands. The calculation of royalties is governed by a labyrinth of interrelated statutes and regulations. The MLA requires lessees to pay a royalty "at a rate of not less than 12½ % in amount or value of the production removed or sold from the lease." 30 U.S.C. § 226(b)(1)(A) (2003). The "value of production" is defined by the so-called "gross proceeds" rule which provides that, for royalty purposes, the value of production shall under no circumstances be less than the gross proceeds earned by the lessee, minus certain allowances for transportation and processing. 30 C.F.R. § 206.153(h) (2002); 30 C.F.R. § 206.157(a) (2002); 30 C.F.R.

§ 206.158 (2002). "Production," as that term is used in the phrase "value of production," is production in marketable condition. *California Co.*, 296 F.2d at 388.

The availability of transportation and processing allowances implicitly recognizes that the government should share in certain costs of production. However, lessees are required to assume the entire cost of placing gas in "marketable condition" and marketing the gas for the mutual benefit of the government and lessee. 30 C.F.R. § 206.153(i) (2002). "Marketable condition" is a term of art defined for purposes of valuation as "lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." 30 C.F.R. § 206.151 (2002). By definition then, "marketable condition" is a fluid concept, wholly dependent on the particular facts of each case.

The marketable condition rule is pivotal in the calculation of royalties because it affects the determination of a lessee's gross proceeds, and therefore the value of production. When value "is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition or to market the residue gas and gas plant products." 30 C.F.R. § 206.153(i). In other words, royalties are due on the value of the gas in a certain condition—marketable condition—whether or not the producer pays the necessary conditioning costs directly or indirectly. The $64,000 question in this case is identifying what condition is "marketable condition" with respect to the gas produced by Plaintiffs.

DISCUSSION

The Payor Letter Does Not Violate the Administrative Procedure Act

Plaintiffs argue that the DOI applied the Dear Operator Letter of April 22, 1996 as an agency rule in violation of the APA. For purposes of the APA, a rule is defined as "the whole or part of an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy or describing the organization, procedure, or practice requirements of an agency." 5 U.S.C. § 551(4) (1991). Agency rules are subject to notice and comment, meaning that an agency must publish a proposed rule in the Federal Register and allow interested parties sufficient time to submit comments. 5 U.S.C. § 553 (1996). Interpretive rules, general statements of policy and rules of agency organization, procedure or practice are exempt from notice and comment procedures. *See id.* at § 553(b)(3)(A). An agency rule issued without notice and comment will be set aside as unlawful unless it falls within one of the three exceptions. 5 U.S.C. § 706(2)(D) (1996).

In both the ARCO/Vastar Decision and the Amoco Decision, the Assistant Secretary determined that the Dear Operator Letter is an interpretation of existing regulations and that the procedural requirements of the APA were therefore inapplicable. *See* ARCO/Vastar Decision at 19; Amoco Decision at 20 (citing *Shalala v. Guernsey Memorial Hospital*, 514 U.S. 87, 115 S.Ct. 1232, 131 L. Ed. 2d 106 (1995)). She further found that the MMS properly applied the valuation regulations as explained by the Dear Operator Letter and noted that the decisions of March 24, 2000 (ARCO/Vastar Decision) and September 12, 2000 (Amoco Decision) modified any inconsistencies between the MMS decision and the regulations that may have existed.

Plaintiffs argue that the Assistant Secretary erred and that the Dear Operator Letter is a substantive rule which

must be set aside because it was never subject to notice and comment. Alternatively, Plaintiff's argue that even if the Dear Operator Letter is not a substantive rule, i.e., it falls within one of the APA's three exceptions, notice and comment was nonetheless required because the Letter effected a change in existing law or policy. Defendants counter that the Dear Operator Letter was not subject to notice and comment because it is not binding on the agency and because it did not introduce a significant change in existing law.

In circumstances substantially similar to the instant case, this Circuit held that an interpretive letter issued by the MMS did not constitute a rule and was therefore not subject to notice and comment. *Babbitt*, 92 F.3d at 1256-57. In *Babbitt*, the Associate Director of Royalty Management, MMS, issued a letter clarifying its treatment of settlement payments. It was part of a series of adjustments made by MMS in the face of fundamental changes in the structure of the natural gas industry and subsequent judicial decisions interpreting legislative intent and agency action. Specifically, the letter at issue in *Babbitt* related to the determination of royalties due on settlement payments made by pipeline purchasers of natural gas to lessees in return for contract amendments or buyouts. The District Court held, and the Court of Appeals affirmed, that the letter itself did not constitute a rulemaking because "nothing in the DOI's procedures vests authority in the Associate Director of the MMS [the letter's author], or even the Director, to issue proclamations binding on the agency . . . [q]uite simply, the May 1993 letter is not an 'agency statement' with 'future effect' since it did not bind the agency in any way." *Babbitt*, 92 F.3d at 1256 (affirming the District Court's unpublished decision in *Independent Petroleum Ass'n of America v. Babbitt*, 1995 WL 431305 at *4 (D.D.C. June 14, 1995)).

The Dear Operator Letter at issue in this case was likewise issued by the Associate Director for Royalty Manage-

ment, MMS, and therefore for the same reasons, it can no more bind the agency than the letter at issue in *Babbitt*. To the extent that the ARCO/Vastar Decision and the Amoco Decision conflict with the above analysis, they are overturned. Nevertheless, the outcome is the same; the Court will not set aside the Dear Operator Letter because it is not a rule and it was therefore not subject to notice and comment.

Plaintiffs' Coalbed Methane Gas Is Not in Marketable Condition at the Wellhead

In their respective appeals to the Assistant Secretary, ARCO/Vastar and Amoco each asserted that the marketable condition rule only requires lessees to place gas in the physical condition necessary to market it under contracts typical for the field or area immediately surrounding the wellhead. Plaintiffs argued that their gas is in marketable condition in its natural state because it can be sold at the wellhead, and therefore they are not required to condition gas for downstream markets. Plaintiffs additionally argued that the MMS's requirement of conditioning gas to the interstate pipeline standard of 2% CO_2 was arbitrary and capricious. The Assistant Secretary flatly rejected both arguments.

Though the Assistant Secretary's Decisions are somewhat circuitous, the underlying rational[e] is sound. After reviewing Plaintiffs' gas sales, she found that most of the gas produced by Plaintiffs from the field or area was conditioned to reduce the level of CO_2 because it was sold for use in distant markets.[3] This was true, the Assistant Secretary noted, whether gas was purchased at the wellhead in its natural state and subsequently conditioned by the purchaser, or purchased at the tailgate of a treatment plant

---

[3] The Assistant Secretary noted that only about 10% of the production from the area was utilized in its untreated form. *See* Amoco Decision at 7-8, n. 11; ARCO/Vastar Decision at 5, n. 7 and 7, n. 9.

after conditioning. The Assistant Secretary further noted that the purchase price of gas purchased at the wellhead in its natural condition was reduced to offset costs incurred by the purchasers to transport and condition gas to remove CO_2. In other words, the Assistant Secretary determined, contracts typical for the field or area involve gas with reduced CO_2 levels, whether the gas is purchased in that condition or whether purchasers perform the conditioning themselves in return for a reduced price, i.e., "[t]he fact that some purchasers are willing to purchase gas prior to conditioning and perform the conditioning themselves does not alter the finding that the gas needs to be conditioned." *See* ARCO/Vastar Decision at 5; Amoco Decision at 9. The Assistant Secretary concluded therefore that gas from the area must have a reduced level of CO_2 to be in marketable condition, and that producers cannot "alter the form of their sales arrangements in order to force the lessor to share in [their] costs to place the product in marketable condition." *See id.* Finally, based on her observation that most of the coalbed methane gas produced by Plaintiffs was sold for use outside the area of production, the Assistant Secretary agreed with MMS that the pipeline standards for CO_2 content effectively established the marketable condition standard.[4]

In the instant appeal, Plaintiffs again argue that gas is in marketable condition at the wellhead in its natural state and that the Assistant Secretary erred in finding otherwise. First, to be clear, Plaintiffs do not question the fact that they must bear the cost of placing the gas in marketable condition. Rather, they argue that the gas at issue is in marketable condition at the wellhead in its natural state as

---

[4] The Assistant Secretary modified the ARCO/Vastar January Order and the Amoco May 27, 1997 Order to the extent that they directed Plaintiffs to recalculate royalties using pipeline quality standards that allowed variable amounts of CO_2 (1-3%) in the gas stream.

evidenced by the existence of wellhead sales. In other words, Plaintiffs would have the Court hold that the simple fact that gas can be sold at the wellhead demonstrates that it is in marketable condition. Defendants argue that the existence of wellhead sales is not determinative of whether gas is in marketable condition. Both parties rely upon *California Co.* for support of their position.

California Co. holds that the marketable condition rule requires the lessees to pay royalties on the costs of placing gas in marketable condition. *California Co.*, 296 F.2d at 388. Calco, a lessee producing oil and gas on federal leases, executed a contract under which it agreed to sell gas "in its natural state suitable for pipeline transmission" at a particular price. *California Co.*, 296 F.2d at 386. Although some of the gas produced by Calco met pipeline requirements in its natural state, some gas required compression or other conditioning to meet the pipeline requirements. *See id.* Calco acknowledged its obligation to market gas removed from the lease, but claimed that it was required to pay royalties only on the price of the gas minus the cost of conditioning. *See id.* at 386-87. Stated another way, Calco argued that it was not required to pay royalties on the cost of conditioning the gas. The Department of Interior thought otherwise. *See id.* at 387.

As described *infra*, the royalty valuation statute requires lessees to pay a royalty of 12½ % of the value of production removed or sold from the lease. 30 U.S.C. § 226(b)(1)(A).[5] In reviewing the agency's decision in *California Co.*, the Court of Appeals focused on the phrase "value of production" and asked whether "production" refers to the raw product regardless of its condition, or the product conditioned for the market in which it is being sold.

---

[5] Though the statute has been amended since *California Co.* was decided, the substance of this particular provision has remained unchanged.

California Co., 296 F.2d at 387. The Secretary of the Department of Interior construed "production" as meaning gas conditioned for market because lessees were obliged to market the product at no cost to the government. *See Id.* at 388. Ultimately, the Court of Appeals for the District of Columbia Circuit agreed, and as a result, Calco was required to pay royalties on the costs of conditioning the gas. The Court of Appeals prefaced their conclusion with a particularly salient observation:

> [t]heoretically, any gas—any "production"—is "marketable." We can assume that, if the price were low enough to justify capital expenditures for conditioning equipment, someone would undertake to buy [gas in its natural condition]. A lessee who sold unconditioned gas at such a price would, in a rhetorical sense, be fulfilling his obligation to "market" the gas, and by thus saving on overhead he might find such business profitable. There is a clear difference between "marketing" and merely selling. For the former there must be a market, an established demand for an identified product. We suppose almost anything can be sold, if the price is no consideration. In the record before us there is no evidence of a market for the gas in the condition as it comes from the wells.

Id. at 387-88.

The distinction between "marketing" and merely "selling" is especially relevant given the facts of this case and the analysis underlying the Assistant Secretary's conclusion that the market for the gas at issue was for gas with reduced levels of CO_2. Based on typical sales contracts for the gas at issue, the Assistant Secretary determined that there was a very limited market for gas in its natural condition, which market consisted of a small local community capable of utilizing gas in spite of high levels of CO_2. The typical sales contract for gas produced in the area was one in which purchasers demanded gas suitable for the actual

market which was distant from the production area. Thus, the actual market was for gas having low levels of CO_2, whether purchasers bought the gas at a reduced price and conditioned it themselves, or whether they purchased the gas at the tailgate of a treatment plant after conditioning.

The cases cited by Plaintiffs are consistent with the holding of *California Co.* and provide no support for their position. In *Xeno, Inc.*, 134 I.B.L.A. 172 (1995), plaintiff, Xeno, together with other lessees from the same producing area, formed a joint venture to purchase gas at the wellheads and resell it to a third party after gathering and compression. *Xeno*, 134 I.B.L.A. at 173-4. Xeno paid royalties on the gross proceeds it received from the joint venture. *See id.* at 174. The State of Montana reviewed Xeno's royalty payments and determined that Xeno improperly deducted gathering and compression charges from its gross proceeds because it had valued lease production on the gross proceeds received from sales to the affiliated joint venture rather than the value established by the arms-length agreement between the affiliated joint venture and the third party. *See id.* The agency agreed with the State of Montana's audit and assessed additional royalties. *See id.* Given the circumstances surrounding the joint venture's formation, the agency presumed that the sole purpose of the affiliated joint venture was to relieve Xeno and the other producers of the cost of gathering and compressing the gas, thereby reducing the amount of gross proceeds against which royalties would be collected. *See id.* at 175. The agency explained that the producers could not reduce the value of the gas for royalty purposes by gathering and compression costs that were necessary to put the gas in marketable condition, regardless of whether the gathering and compression was performed before or after being sold to the joint venture. *See id.*

Upon review, the administrative judge determined that the MMS incorrectly determined that gathering and com-

pression were necessary *per se* to place the gas in marketable condition. *Xeno*, 134 I.B.L.A. at 182. The administrative judge found no evidence in the record of any analysis by the MMS of what constituted marketable condition for the gas at issue. *See id.* This was in stark contrast to substantial evidence provided by Xeno of competing offers from firms other than the affiliated joint venture to purchase gas at the wellhead prior to gathering or compression for similar or higher prices. *See id.* at 182-83. Thus, "unlike the record in *California Co.* there [was] evidence of a market for the gas at the wellhead." *Id.* at 183. The existence of competing offers to buy gas at the wellhead indicated that there was in fact a market for the gas at the wellhead in its natural condition and that gathering and compression were not necessary to place the gas in marketable condition. Therefore the gathering and compression costs were properly excluded from Xeno's royalty calculation. *See id.*

The Tenth Circuit approved the rationale of *Xeno* in *Amerada Hess Corp. v. Dept. of Interior*, 170 F.3d 1032 (10th Cir.), though the outcome was not the same. The issue in *Amerada Hess* was whether royalties were owed on reimbursements received by the producers for certain production-related costs. *Amerada Hess*, 170 F.3d at 1036. The court ultimately held that royalty was owed on such costs. However in arriving at its conclusion the court distinguished the case from *Xeno*, stating that "*Xeno* reached a different result because the producer company in that case showed that its gas was in marketable condition and could be sold directly from the wellhead . . . [plaintiff] has made no such showing here, and therefore cannot benefit from the DOI's ruling in *Xeno*." *See id.* at 1037.

Plaintiffs additionally rely upon *Beartooth Oil and Gas Co. v. Lujan*, No. 92-99 (D.Mont. Sept. 22, 1993) (vacating and remanding *Beartooth Oil and Gas Co.*, 122 I.B.L.A. 267 (1992)). In *Beartooth*, the plaintiff, Beartooth, sold gas at

the wellhead to Mesa, which in turn sold the gas to Mountain Fuel. *Beartooth*, slip op. at 2. None of the companies were affiliated and each of the sales agreements were arms length. *See id.* The price Mesa paid Beartooth (and on which Beartooth paid royalties) was based on the price Mesa received from Mountain Fuel, reduced by certain factors including the cost of compression for delivery to Mountain Fuel. Beartooth appealed the agency's order demanding royalties for the amount the Mesa/Mountain Fuel price was reduced for compression costs. *Beartooth*, slip op. at 2-3.

The court vacated and remanded the agency's decision because the agency failed to determine what constituted "marketable condition" for the gas at issue. The court found that the MMS acted arbitrarily and capriciously because it did not consider whether or not the contract for sales of the gas at issue was "typical for the field." *Beartooth*, slip op. at 4. Rather, as it did in *Xeno*, MMS assumed that gas was not in marketable condition unless it was compressed. *See id.* at 5. The Court recognized in *Beartooth* that:

> Mesa may or may not be performing conditioning necessary to place Beartooth's gas into 'marketable condition.' However, until the IBLA first establishes what specifically constitutes 'marketable condition' for gas produced from the lease, it is arbitrary and capricious to conclude the gas as sold to Mesa was not in marketable condition.

Id. at 10.

Plaintiffs argue that the foregoing cases stand for the premise that gas is in marketable condition at the wellhead simply because it is sold at the wellhead. However, this construction is too narrow. In both *Xeno* and *Beartooth*, the agency's determination that gas was not in marketable condition at the wellhead was overturned because the agency failed to determine what constituted marketable

condition under the particular circumstances of the case—not because the gas was in marketable condition at the wellhead. The existence of wellhead sales are one factor to consider in identifying marketable condition, but it is not the determinative factor, in part because it overlooks the plain language of the applicable regulations.

The marketable condition rule anticipates and prohibits the type of arrangements alluded to in *California Co.* and which the agency mistakenly assumed existed in *Xeno*, wherein producers offer reduced prices to purchasers who in turn incur the costs of placing gas in marketable condition. Specifically, the rule requires lessees to

> place gas in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition or to market the gas.

30 C.F.R. § 206.152(i) (2002).

The Court's role is to decide whether the agency's interpretation and application of the "marketable condition" rule in this case is reasonable. After reviewing the evidence presented by the parties and the marketable condition rule, the Assistant Secretary determined that in this case, the gas at issue is not marketable unless it has reduced levels of CO_2. Since lessees must bear the cost of placing gas in marketable condition, it makes no difference whether purchasers buy the gas at the wellhead for a reduced price or at the tailgate of a treatment plant after conditioning. The Court finds that, under the particular circumstances in this case, the Assistant Secretary's decision is a reasonable applica-

tion of the marketable condition rule. Therefore, Plaintiffs must pay royalties on the cost of conditioning the gas to reduce CO_2 levels.

Limitations on Transportation Allowances Are Appropriate

Though lessees are required to place gas in marketable condition at no cost to the government, they are permitted to deduct from the value of production certain reasonable and actual transportation costs. 30 C.F.R. § 206.156 (2002). Plaintiffs argue that the Assistant Secretary's determination that transportation costs for CO_2 levels in excess of pipeline quality standards are not deductible is in error because the transportation and removal of CO_2 is "directly related" to transportation of lease production.

As discussed *infra*, the gas at issue must have a reduced level of CO_2 to be in marketable condition; therefore, lessees bear the costs associated with removing excess CO_2. The Assistant Secretary observed that "transportation of the CO_2 to the treatment plant in this instance is a service that is inextricably tied to placing the gas in marketable condition because the CO_2 is extracted at the plant." ARCO/Vastar Decision at 15. She reasoned that the cost of transporting excess CO_2 from the wellhead to the conditioning facility was a marketing cost and could not be deducted as transportation costs.[6] As a result, the cost of transporting coalbed methane and 2% CO_2 from the wellhead to the conditioning plant was permitted as a transportation allowance and cost of transporting excess CO_2 was not.

---

[6] Plaintiffs additionally challenge the Assistant Secretary's alternative rationale which turned on whether excess CO_2 is properly identified as a "waste" product or a "non-royalty" product. However, the Court need not address Plaintiffs' arguments on this issue since the Assistant Secretary's decision is affirmed on the grounds that marketing costs cannot be deducted as transportation costs.

The cases upon which Plaintiffs rely for their position are readily distinguishable from the facts of this case. *Marathon Oil Co. v. United States*, 604 F. Supp. 1375, 1378 (D. Alaska 1985), stemmed from a controversy between a lessee and MMS involving the proper method of valuing natural gas at the wellhead for royalty purposes. The marketable condition rule was not a factor in the court's finding that the costs of liquefying natural gas were incurred to facilitate transportation. *Marathon*, 604 F. Supp. at 1385-87. Similarly, in *Exxon Corp.*, 118 I.B.L.A. 221 (1991), the Interior Board of Land Appeals determined that dehydration of the gas at issue was not necessary to satisfy market specifications but rather was performed for the sole purpose of facilitating transportation. *Exxon Corp.*, 118 I.B.L.A. at 241. In contrast, CO_2 removal is essential in the instant case to place gas in marketable condition. That there exists a corollary benefit in reducing the level of CO_2 does not transform what is a marketing cost into a transportation cost. The Court therefore finds that the Assistant Secretary's application of the regulations relating to transportation allowances to the circumstances of this case is reasonable, and for that reason, Plaintiffs' appeal thereof is denied as to this issue.

ARCO/Vastar Is Not Entitled to an Extraordinary Processing Allowance

As described *infra*, lessees pay royalties on the value of production removed or sold from the lease. "Value of production" is defined by regulations promulgated by MMS and includes allowances that permit lessees to deduct certain transportation and processing costs from the royalty value. Lessees may not take deductions for costs incurred to place production in marketable condition or for processing lease production which is not royalty bearing. 30 C.F.R. § 206.158(d)(1) (2002). Lessees may however apply to MMS for an allowance for extraordinary processing costs, i.e., those shown to be extraordinary, unusual or un-

conventional as compared to standard industry conditions and practice. 30 C.F.R. 206.158(d)(2)(i). Guidelines issued by MMS on March 19, 1996, set forth the following factors MMS considers in evaluating an application for extraordinary processing costs: (1) the composition of the gas stream being processed; (2) the complexity of the gas plant design compared to conventional or typical gas processing plants, as well as the methods used to process the gas to remove elements or compounds from the gas; and (3) the unit costs incurred to recover the principal product, usually methane. *See* ARCO/Vastar Administrative Record, tab 23-2, MMS Guidelines for Extraordinary Processing Cost Recovery, March 19, 1996 ("March 19 Guidelines").

On April 29, 1997, Vastar requested approval for an extraordinary cost allowance for the cost of removing CO_2 from its gas stream. The RVD Decision denied Vastar's application because MMS determined that Vastar did not "compellingly demonstrate that the resource, plant design or unit costs are extraordinary, unusual or unconventional" and because "[r]egulations at 30 C.F.R. § 206.158(d)(1) (1996) disqualify a processing allowance for this case." *See* RVD Decision at 1. Vastar appealed the RVD Decision to the Assistant Secretary who, after reviewing the decision and considering the parties' arguments, agreed that ARCO/Vastar was not entitled to an extraordinary processing allowance.

ARCO/Vastar appeals the Assistant Secretary's decision arguing that it is arbitrary and capricious. ARCO/Vastar asserts that the Assistant Secretary ignored the DOI's own precedent because it had previously approved an extraordinary processing allowance for the Louisiana Land and Exploration Company for costs incurred in removing CO_2. ARCO/Vastar additionally argues that an extraordinary processing cost allowance is permitted under the March 19 Guidelines when gas plant products (in this case, CO_2) are vented into the air rather than being sold as a separate pro-

duct. Finally, ARCO/Vastar argues that coalbed methane gas as a product is eligible for an extraordinary cost allowance.

The ARCO/Vastar Decision is not arbitrary and capricious as the Assistant Secretary fully and carefully considered the prerequisites necessary for an extraordinary processing cost allowance before agreeing with MMS that ARCO/Vastar was ineligible. At the outset of the decision, the Assistant Secretary observed that ARCO/Vastar was not entitled to a processing allowance for the costs of CO_2 removal under 30 C.F.R. § 206.158(d)(1) because such conditioning was necessary to place the gas in marketable condition (a cost lessees must bear alone) and because the CO_2 was vented into the air rather than being captured and sold as a royalty bearing product. The Assistant Secretary then turned to the issue of whether CO_2 removal qualified as an extraordinary processing cost under 30 C.F.R. § 206.158(d)(2)(i) and the March 19 Guidelines.

The Assistant Secretary agreed with ARCO/Vastar that its gas is "atypical" due to the high CO_2 content, but stated that this determination alone was not dispositive, presumably because the design of the Val Verde plant and the process used to remove the CO_2 must also be considered. *See* ARCO/Vastar Decision at 12; *see also*, March 16 Guidelines. Though ARCO/Vastar attempted to distinguish the Val Verde plant from conventional plants by focusing on the type, concentration and amount of amine used and the amount of water required to remove CO_2 from the gas stream, the Assistant Secretary concluded that the use of amine in gas processing plants is common and the Val Verde plant itself was relatively simple compared to other conventional gas processing plants because its only function is to remove CO_2. *See id.* at 12. Finally, the Assistant Secretary was unable to evaluate whether ARCO/Vastar's costs were typical or extraordinary because ARCO/Vastar failed to provide standard industry costs for CO_2 removal.

Rather it simply argued that its cost of $0.0778 per Mcf to recover methane is "significant." *See id.* at 13.

ARCO/Vastar's argument that it is entitled to an extraordinary processing cost allowance because of the agency's decision regarding extraordinary processing cost allowances for Louisiana Land and Exploration Company ("LL & E") is entirely without merit. *See* ARCO/Vastar Administrative Record, tab 13-3, MMS letter to The Louisiana Land and Exploration Company, March 15, 1996 ("LL & E Letter"). First, the regulation requires lessees to apply to the MMS for an extraordinary processing cost allowance, which will be granted "only if the lessee can demonstrate that the costs are, by reference to standard industry conditions and practices, extraordinary, unusual, or unconventional." 30 C.F.R. § 206.158(d)(2)(i). In other words, extraordinary processing cost allowances are approved on a case by case basis and are necessarily dependent on the specific facts of each case.

Second, unlike ARCO/Vastar, LL & E demonstrated that not only its gas but also its plant design and costs were extraordinary, unusual or unconventional in comparison to standard industry conditions. LL & E's gas was atypical because it contained no natural gas liquids ("NGLs") and was comprised of 20% CO_2 and 12.6% hydrogen sulfide (H_2S). *See* LL & E Letter at 3. MMS noted that "[t]his gas is the only gas stream in the continental U.S. containing such high levels of both CO_2 and H_2S, with no NGLs."[7] *See id.* Further complicating matters was the fact that the gas

---

[7] ARCO/Vastar argues that it is entitled to an extraordinary processing cost allowance because with respect to LL & E "the MMS relied on the absence of liquids in a gas stream for its finding that the gas was atypical and qualified for an extraordinary processing allowance." *See* Plaintiffs' Joint Memorandum of Points and Authorities in Support of Motions for Summary Judgment at 52. However, this is a misstatement as MMS plainly did not rely solely on the fact that LL & E's gas contained no NGL's.

produced by LL & E was significantly hotter than conventional gas streams. *See id.* The MMS found that the high temperature of the LL & E gas combined with its highly acidic composition necessitated a unique and complex processing unit. *See id.* In contrast, the Assistant Secretary noted that the amine process used in the Val Verde plant is "quite common" and the plant itself is "composed of only one part of what is considered a fairly complex natural gas processing plant." *See* ARCO/Vastar Decision at 12. Finally, LL & E provided both its own processing costs and typical industry costs of processing acidic gas streams, enabling MMS to compare the two and determine that in fact LL & E's processing costs were extraordinary. *See id.* at 4. ARCO/Vastar did not provide standard industry costs for recovering methane, but rather expected the Assistant Secretary to rely on its assertion that its costs were "significant."

ARCO/Vastar's remaining arguments are merely unsupported assertions. ARCO/Vastar does not explain why the March 16, 1996 Guidelines would permit an extraordinary processing cost allowance when gas plant products such as CO_2 are vented into the air rather than being sold as a separate product. Nor does ARCO/Vastar describe why coalbed methane gas as a product is eligible for an extraordinary cost allowance.[8] As a result, ARCO/Vastar's appeal is denied as to this issue.

---

[8] ARCO/Vastar consistently compares its gas to non-coalbed natural gas in order to justify an extraordinary processing allowance. However, MMS sensibly explained in the RVD Decision why such a comparison is inapplicable:

> [n]atural gas has diverse characteristics in terms of geologic setting, reservoir properties, operational requirements and particularly composition. Although one may classify natural gas into certain categories, such as sweet gas, sour gas, wet gas, dry gas, associated gas or even coalbed gas, each gas occurrence has individual characteristics that differentiate it to some degree

Late Payment Interest Is Due on Additional Royalties

In the January Order, MMS stated that late payment interest would be calculated and assessed upon receipt of payment of additional royalties. *See* January Order at 8. The Assistant Secretary sustained the assessment of late payment interest in the ARCO/Vastar Decision because she determined that it was supported by longstanding precedent. *See* ARCO/Vastar Decision at 19.

The government's right to interest on late royalty payments is statutorily recognized in FOGRMA, which states that:

> in the case of oil and gas leases where royalty payments are not received by the Secretary on the date that such payments are due, or are less than the amount due, the Secretary shall charge interest on such late payments or underpayments at the rate applicable under section 6621 of Title 26. In the case of an underpayment or partial payment, interest shall be computed and charged any on the amount of the deficiency and not on the total amount due.

30 U.S.C. § 1721(a) (2003).

Likewise, the implementing regulation issued by MMS states that "an interest charge shall be assessed on unpaid and underpaid amounts from the date the amounts are due." 30 C.F.R. § 218.54(a) (2002). The imposition of late payment interest charges is intended to compensate the government for the time value of money due to it but not timely paid. *See Meridian Oil, Inc.*, 140 I.B.L.A. 135, 143

---

from another. In this respect it can be argued that each natural gas is unique in some manner.

See RVD Decision at 3-4.

In other words, the real question is not whether coalbed methane gas is atypical (which the Assistant Secretary determined it was), but whether the coalbed methane gas produced by Vastar is atypical or unusual.

(1997). The language of the statute and implementing regulation indicates that the assessment of late payment interest is not discretionary.

ARCO/Vastar argues that "imposition of late payment interest would be inequitable" and urges the Court to relieve it of late payment interest charges as the court did in *Jicarilla Apache Tribe v. Continental Oil Co.*, No. 76-430 (D.N.M. November 21, 1988) ("*Conoco*"). Plaintiff's reliance on the *Conoco* decision is misplaced however because it dealt with the payment of *prejudgment* interest and because the lessees in the case were ultimately required to pay *postjudgment* interest.

In *Conoco*, the court found, in relevant part, that lessees owed additional royalties in an amount to be calculated by the agency within a set time. The court declined to assess *prejudgment* interest at the time of its decision because it was not "appropriate on a debt which is unliquidated and incapable of calculation prior to judgment." *Conoco*, Findings of Fact and Conclusions of Law, May 13, 1998, at 17. Following the *Conoco* decision, the amount of royalties owed by the lessees was calculated and the MMS issued three Orders assessing additional royalties and corresponding late payment interest. The IBLA sustained the assessment of late payment interest on appeal. In its analysis, the IBLA reviewed 30 U.S.C. § 1721(a) and 30 C.F.R. § 218.54(a), and determined that "the court's denial of prejudgment interest [in *Conoco*] does not bar MMS from seeking postjudgment interest on those underpayments . . . [i]ndeed, MMS is statutorily required to do so." *Meridian Oil, Inc.*, 140 I.B.L.A. at 144.

As the IBLA observed in *Meridian*, the mandatory nature of the statutory and regulatory language pertaining to the payment of late payment interest speaks for itself, and for that reason, the Court will not set aside the Assistant Secretary's assessment of late payment interest.

The Amoco Decision Does Not Violate the Statute of Limitations

Amoco argues that the agency is barred from collecting royalties accrued more than six years prior to the May 27, 1997 Order by the statute of limitations set forth in 28 U.S.C. 2415(a):

> [s]ubject to the provisions of section 2416 of this title, and except as otherwise provided by Congress, every action for money damages brought by the United States or an officer or agency thereof which is founded upon any contract express or implied in law or fact, shall be barred unless the complaint is filed within six years after the right of action accrues or within one year after final decisions have been rendered in applicable administrative proceedings required by contract or by law, whichever is later . . . .

28 U.S.C. § 2415(a) (1994).

The Assistant Secretary denied Amoco's appeal on this issue stating that the statutory bar was inapplicable because the proceeding was an administrative appeal. *See* Amoco Decision at 21. Her decision was consistent with longstanding I.B.L.A. precedent. *See Foote Mineral Co.*, 34 I.B.L.A. 285, 306-308 (1978); *Anadarko Petroleum Corp.*, 122 I.B.L.A. 141, 148 (1992) (holding that § 2415(a) does not apply to administrative proceedings); *Meridian Oil, Inc.*, 140 I.B.L.A. 135, 145 (1997) (stating that "we have long ruled that statutes establishing time limitations for the commencement of judicial actions for damages on behalf of the United States do not limit administrative proceedings within the DOI").

In 1996, Congress amended FOGRMA by enacting a seven year statute of limitations on lease-related demands, specifically "a judicial proceeding or demand which arises from, or relates to an obligation, shall be commenced within seven years from the date on which the obligation becomes

due and if not so commenced shall be barred." 30 U.S.C. § 1724(b)(1) (2003). The amendment explicitly precludes the application of the statute of limitations set forth in 28 U.S.C. § 2415 to any obligation arising under FOGRMA. 30 U.S.C. § 1724(b)(3). Unfortunately, the provisions of the amended statute do not control this case because it relates to gas produced between January 1989 and August 1996; the seven year statute of limitations of § 1724(b)(1) applies only to oil and gas production occurring after its effective date of September 1, 1996. As a result, the Court must determine whether 28 U.S.C. 2415(a) bars the agency from collecting royalties due more than six years prior to the May 27, 1997 MMS Order.

The Court's inquiry must begin with the language of the statute itself. *Butler v. West*, 164 F.3d 634, 639 (D.C. Cir. 1999). In addition, the United States Supreme Court has held that "statutes of limitation sought to be applied to bar rights of the Government . . . must receive a strict construction in favor of the Government." *Badaracco v. Comm'r of Internal Revenue*, 464 U.S. 386, 391, 104 S.Ct. 756, 78 L. Ed. 2d 549 (1984) (quoting *E.I. Dupont De Nemours & Co. v. Davis*, 264 U.S. 456, 462, 44 S.Ct. 364, 68 L.Ed. 788 (1924)). Complicating matters is the existence of a circuit split as to whether 28 U.S.C. § 2415(a) applies to MMS orders to collect additional royalties.

Plaintiffs rely primarily upon a relatively recent en banc decision in which the 10th Circuit held that 28 U.S.C. § 2415(a) barred an MMS order directing lessees to pay additional royalties on production produced before September 1, 1996. *OXY USA, Inc. v. Babbitt*, 268 F.3d 1001 (10th Cir. 2001) ("*OXY USA II*").[9] *OXY USA II*

---

[9] Plaintiffs additionally cite a decision by the United States District Court for the District of Alaska which applied § 2415(a) to an MMS order seeking additional royalties because it found such efforts "more analogous to actions at law for damages than to actions in

stemmed from a December 1996 order issued by MMS directing lessees to pay additional royalties for oil produced from federal leases between January 1980 and September 1983. *OXY USA II*, 268 F.3d at 1003-1004. Lessees filed suit in district court seeking a declaration that the claim for royalties was time barred by 28 U.S.C. § 2415(a). *See id.* The district court, relying on language in *Phillips Petroleum Co. v. Lujan*, 4 F.3d 858, 860 & n. 1 (10th Cir. 1993), determined that § 2415(a) barred the MMS order and granted summary judgment in favor of lessees.[10] *See id.* On appeal, a divided panel of the 10th Circuit Court of Appeals reversed, holding that § 2415(a) was inapplicable because MMS orders are not "actions" as contemplated by the statute. *OXY USA, Inc. v. Babbitt*, 230 F.3d 1178, 185-90 (10th Cir. 2000) ("*OXY USA I*").

The 10th Circuit granted a Petition for Rehearing and after a methodical analysis, concluded that "the statutory language, together with a forthright statutory scheme and purpose, clearly instruct that the six year statute of limitation[s] under 28 U.S.C. § 2415(a) applies to the MMS orders in this case." *OXY USA II*, 268 F.3d at 1005. Upon concluding that the statutory time bar of 28 U.S.C. § 2415(a) applied, the 10th Circuit vacated *OXY USA I* and affirmed the district court's order granting summary judgment to the lessees. *See id.* at 1008.

In the en banc decision, the 10th Circuit first considered the phrase "every action" in § 2415(a) and found it to be "patently broad" and ultimately inclusive of administrative

---

equity for restitution." *Marathon Oil Co. v. Babbitt*, 938 F. Supp. 575, 578 (D. Alaska 1996).

[10] The court in *Phillips Petroleum v. Lujan* accepted without discussion the parties' agreement that 28 U.S.C. § 2415(a) applied to the government's effort to collect royalty underpayment and agreed with the parties that the oil and gas leases at issue were contracts. *Phillips Petroleum v. Lujan*, 4 F.3d at 860.

collection proceedings such as the MMS order at issue. *Id.* at 1005. The statute's subsequent reference to a "complaint" did not limit its application to formalized judicial proceedings, the 10th Circuit stated, in light of "the statute's obvious purpose to level the playing field between the government and private litigants by forcing the government to promptly assert its claims [and a] reading of the entire text of § 2415, including subsections (f) and (i)." *Id.* Subsection (f) allows the United States to assert, in an action against it, a counter claim or offset against a party under certain conditions. 28 U.S.C. § 2415(f). Subsection (i) permits the United States to collect a claim by means of administrative offset. 28 U.S.C. § 2415(i). The 10th Circuit found these provisions demonstrative of Congressional intent for "§ 2415(a) to encompass more than the filing of a 'complaint' in court." *Id.* at 1006.

Notwithstanding lessees' statutory obligation to make royalty payments on production from federal leases, the 10th Circuit concluded that the MMS royalty collection order was founded on contract. *See id.* at 1007. The Circuit next rejected the distinction recognized by the 5th Circuit in an unpublished decision between "contractual obligations," i.e., royalties due on production, and money damages, finding that it too narrowly construed the phrase "money damages." *See id.* at 1007-1008 (referring to the 5th Circuit's decision in *Phillips Petroleum Co. v. Johnson*, 1994 WL 484506 (5th Cir.) ("*Phillips Petroleum*")). The Circuit stated that *Bowen v. Massachusetts*, 487 U.S. 879, 108 S.Ct. 2722, 101 L. Ed. 2d 749 (1988), upon which the 5th Circuit relied in *Phillips Petroleum*, was "neither binding nor persuasive" and held that the MMS order was an action for money damages because it was "substantively indistinguishable from other government claims to recover money owed under contracts governed by the limitations period in § 2415(a)." *Id.*

Finally, the 10th Circuit determined that FOGRMA's seven year statute of limitations did not trigger the "except as otherwise provided by Congress" exception of 28 U.S.C. § 2415 "because [the FOGRMA limitation] applied only to oil and gas production occurring after its effective date of September 1, 1996." *Id.* at 1009. The 10th Circuit further reasoned that Congress would not have amended FOGRMA to include a statute of limitations if it believed that the provisions therein and the enacting regulatory scheme otherwise superceded 28 U.S.C. § 2415(a). *See id.*

Defendants argue that § 2415(a) cannot apply to this case because it is not a complaint or action brought by the United States for money damages. Defendants refer to the unpublished 5th Circuit decision in *Phillips Petroleum* holding that § 2415(a) did not apply to an MMS order to collect additional royalties because "actions that don't involve the filing of a complaint are not 'action[s] for money damages'" as contemplated by the statute. *Phillips Petroleum*, 1994 WL 484506, *1. In addition, as mentioned above, the 5th Circuit noted in *Phillips Petroleum* the distinction between "money damages," which generally refers to a sum of money used as compensatory relief, and the contractual obligations sought by the MMS, and held that "[s]uch contractual obligations cannot be considered compensatory." *Id.* (citing *Bowen v. Massachusetts*, 487 U.S. 879, 897, 108 S.Ct. 2722, 101 L. Ed. 2d 749 (1988)).

More persuasively however, Defendants also rely upon a decision by the United States District Court for the District of Columbia, which held that the limitation of § 2415(a) did not act as a time bar to an MMS order to collect additional royalties and associated interest. *Samedan Oil Corp. v. Deer*, 1995 WL 431307 (D.D.C.) *rev'd on other grounds*, *IPAA v. Babbitt*, 92 F.3d 1248, 1260 (D.C. Cir.) ("[b]ecause we conclude that DOI cannot collect any royalties on the settlement payment, it is unnecessary for us to consider appellant Samedan's statute of limitations claim"). At issue

in *Samedan* was a December 1993 MMS order directing the lessee to pay royalties due on production produced between February 1988 and November 1989. *Samedan* at *1. In October 1994, after the agency affirmed the order, the lessee filed suit in court seeking to enjoin the order. *See id.* The government filed a counterclaim to enforce the order in November 1994. *See id.* The lessee argued in *Samedan* that the six year statute of limitations of § 2415(a) barred the collection of royalties due prior to October 31, 1988 because the "complaint" to enforce an "action for money damages," i.e., the MMS order, was the government's November 1994 counterclaim. *See id.* at *3. As in this case, the government argued that § 2415(a) did not apply.

The district court first decided that the lease, while it referred to and incorporated certain statutes and regulations, was founded on contract as evidenced by numerous contractual provisions such as the lease term, royalty rate, timing and frequency of payments, and record-keeping and reporting requirements. *See id.* at *4-5. Though separately the terms were not determinative of the existence of a contract, together the district court found that they "are integral to an interpretation of the lease [and] are beyond mere backdrop for an incorporated statute . . . the statute and the regulations play an interstitial role in an otherwise self-contained document." *Id.* at *5.

The district court next agreed with the government's position that the additional royalties sought by the MMS were "not money damages because they are not compensatory, but rather something to which the government is already entitled under the terms of the lease." *See id.* at *5. Looking to the 5th Circuit's decision in *Phillips Petroleum* and the Supreme Court's decision in *Bowen v. Massachusetts*, 487 U.S. at 893, 108 S.Ct. 2722 (stating that "the fact that a judicial remedy may require one party to pay money damages to another is not sufficient reason to characterize the relief as 'money damages'"), the court held that

§ 2415(a) was inapplicable because "DOI's claim is not to recover damages; it is to collect royalties payable under the terms of the Samedan lease." *Id.* at *6.

The district court next turned to the term "action" as used by the statute in the phrase "action for money damages." The lessee in *Samedan* urged the district court to extend the term "action" to include administrative proceedings. *Samedan* at *7. The district court found the 5th Circuit's opinion in *Phillips Petroleum* controlling and declined the lessee's invitation, reasoning that:

> [o]nly if "action" includes administrative proceedings but "complaint" is confined to judicial pleadings, might Samedan prevail. That construction, however, violates the sense of the statute. Section 2415(a) states that "every action for money damages . . . shall be barred unless the complaint is filed within six years . . . ." Use of the definite article 'the' to modify 'complaint'—instead of the indefinite article 'a'—tells us that a particularized 'complaint' has been previously specified by context . . . it is clear that the antecedent of 'complaint' is 'action.'

Id.

The district court therefore held that "action" as used in § 2415(a) applied to "judicial but not to administrative proceedings," and that the judicial action before the court (i.e., the government's counterclaim for summary judgment to enforce the administrative order) was an action to enforce an administrative order, not to collect money damages. *Id.* at *7-9.

To summarize, although the MMS order was based on contract, the United States District Court for the District of Columbia held in *Samedan* that § 2415(a) was no bar to the MMS order because the government was not pursuing "money damages" and because the government's claim was not an "action" as those terms are used in the statute. *See*

also, Vastar Resources, Inc. v. Armstrong, No. 94-02040 (D.D.C. Aug. 27, 1997); *but see, Fina Oil & Chemical Co. v. Norton*, 209 F. Supp. 2d 246, 257 (D.D.C. 2002) (finding that the six year statute of limitations under § 2415(a) applied, but holding that it did not bar the action before the court because it was brought by the lessee) *rev'd on other grounds, Fina Oil & Chemical Co. v. Norton*, 332 F.3d 672 (2003).

The Court finds the logic underpinning the district court's decision in *Samedan* persuasive. Therefore, upon review of the statute and consideration of the facts of this case, the Court holds that § 2415(a) does not bar the collection of royalties due six years prior to the May 27, 1996 MMS Order in this case for the following reasons. First, as in *OXY USA II* and *Samedan*, the royalty claims at issue in this case arise from the lease, i.e., a contract. Nevertheless, the MMS Orders which Plaintiffs appeal do not seek money damages, but rather claim royalties due under the lease. *Samedan* at *6. Furthermore, the relationship between "action" and "complaint" in the statute indicates that the statute applies to judicial proceedings, not administrative orders. *Samedan* at *7. Finally, the statute plainly bars "every action for money damages *brought by the United States*." The action currently before the court was not brought by the United States, it is an appeal of administrative orders brought by Plaintiffs pursuant to the Administrative Procedure Act and other statutes. Moreover, unlike the circumstances in *Samedan*, the government has not filed a counterclaim to enforce the May 1997 Order. Therefore, Amoco's Motion for Summary Judgment is denied with respect to this issue.

CONCLUSION

For the reasons set forth herein, in an accompanying Order, the Court will deny the Plaintiffs' Motions for

Summary Judgments and grant the Defendants' Motion for Summary Judgment.

APPENDIX C

UNITED STATES DISTRICT COURT, DISTRICT OF COLUMBIA

AMOCO PRODUCTION COMPANY,
PLAINTIFF,

v.

SYLVIA V. BACA, ET AL.,
DEFENDANTS.

VASTAR RESOURCES, INC. AND ATLANTIC RICHFIELD COMPANY,
PLAINTIFFS,

v.

SYLVIA V. BACA, ET AL.,
DEFENDANTS.

NOS. CIV.A. 00-02933 (WBB),
CIV.A. 00-01480 (WBB)

Nov. 14, 2003.

ORDER

Upon consideration of the parties' cross motions for summary judgment and the entire record herein, for the reasons set forth in the accompanying Memorandum, it is on this 14th day of November, 2003, hereby

ORDERED that Plaintiffs' Motions for Summary Judgment are DENIED in their entirety, and is it further

ORDERED that Defendants Motion for Summary Judgment is GRANTED in its entirety.

/s/ William B. Bryant
Senior United States District Court Judge

APPENDIX D

[Seal Omitted]

United States Department of the Interior

OFFICE OF THE SECRETARY

WASHINGTON, D.C. 20240

February 27, 2001

CERTIFIED MAIL
Return Receipt Requested

Mr. Charles A. Breer
Attorney for Vastar Resources,
Inc. and Atlantic Richfield Company
370 17th Street - Suite 4700
Denver, Colorado 80201-0185

Re: MMS-97-0063-O&G
MMS-97-0191-O&G
ARCO/Vastar

Petition for
Reconsideration
Denied

Dear Mr. Breer:

Atlantic Richfield Company and Vastar Resources, Inc. (ARCO/Vastar, the Petitioner) petitioned the Department of the Interior (Department) for reconsideration of the March 24, 2000, decision (Decision) in the above-referenced appeals issued by Sylvia V. Baca, the Assistant Secretary for Land and Minerals Management.[1] The Decision denied, in part, the appeals and modified the Minerals Management Service's (MMS) order dated January 22, 1997 (Order), which directed ARCO/Vastar to pay additional royalties and

---

[1] *See Atlantic Richfield Co.*, MMS-97-0063-O&G, MMS-97-0191-O&G (March 24, 2000), 22 Gower Federal Service, Royalty Valuation and Management, Rocky Mtn. Min. L. Found.

to perform a restructured accounting and pay additional royalties due. The Order applies to all of ARCO/Vastar's San Juan Basin Federal and Indian leases[2] producing coalbed methane that is transported and processed through the Val Verde System for the period January 1989 through August 1996 (audit period).

In the Decision, the Department determined that:

1) the cost of CO_2 removal was not deductible in determining the value of production for royalty purposes because

(a) placing the coalbed gas in marketable condition at no cost to the lessor is required by the valuation regulations, and

(b) the CO_2 removal at issue does not qualify for an extraordinary processing cost allowance under the valuation regulations;

2) the cost of transporting CO_2 in excess of the applicable mainline specifications is not deductible from the value of production for royalty purposes because the cost of transporting non-royalty-bearing production cannot be deducted from the value of royalty bearing production;

3) the interpretation of existing rules contained in MMS's April 22, 1996, Dear Operator/Payor Letter does not violate the Administrative Procedure Act; and

4) late payment interest is applicable to past-period deficient royalties.

---

[2] The Order was modified by the Decision to eliminate from consideration the valuation of coalbed methane from any Indian leases. *See* Decision at 1. n.2.

ARCO/Vastar now assert in their petition for reconsideration that MMS's conclusions concerning the marketability of the gas at the wellhead and concerning ARCO/Vastar's obligation to assume the conditioning costs necessary to meet mainline standards are factually and legally wrong. Petition for Reconsideration (Petition) at 1-2. In support of their arguments, ARCO/Vastar rely on the decision in *Independent Petroleum Ass'n of America v. Armstrong*, 91 F. Supp. 2d 117 (D.D.C. 2000), *appeal filed*, Nos. 00-5404 and 00-5405 (D.C. Cir.) (*IPAA v. Armstrong*), and affidavits executed by Dr. Alfred L. Parker and Mr. Peter Mueller.[3] Petition at Exhibit B, Parker Affidavit; Petition at Exhibit C, Mueller Affidavit.

Issue

Is the information submitted by ARCO/Vastar sufficient to support its request for reconsideration?

Analysis

1. Does *IPAA v. Armstrong* apply?

ARCO/Vastar misconstrues the decision in *IPAA v. Armstrong*. The issues in *IPAA v. Armstrong* involved primarily whether the lessee may deduct so-called "downstream" marketing costs in determining royalty value. Treatment of gas to put it in marketable condition was not at issue in *IPAA v. Armstrong*. Even the plaintiffs in that case did not dispute the marketable condition obligation. *See IPAA v.*

---

[3] The affidavits were filed by Amoco Production Company (Amoco) in a related coalbed methane case affecting some of the same leases as the instant case. Petition at 2, n.2. By letter dated June 2, 2000, counsel for Amoco transmitted a supplemental affidavit from Dr. Parker revising and correcting information included in Dr. Parker's March 27, 2000, affidavit.

Armstrong, 91 F. Supp. 2d at 123. Further, the District Court, in granting the government's motion to alter or amend under Rule 59(e), Fed. R. Civ. P., which the plaintiffs did not oppose in this respect, agreed that the lessee's duty to place gas in marketable condition was not challenged or affected by the ruling in that case.

Therefore, *IPAA v. Armstrong* provides no support for ARCO/Vastar's position or its petition for reconsideration.

2. Do the Parker and Mueller affidavits present new factual information regarding what constitutes marketable condition for the coalbed gas?

Essentially, ARCO/Vastar's argument concerning marketable condition has not changed. ARCO/Vastar now aver that the Department, in reaching its decision, relies on erroneous assumptions that are unsupported by evidence. ARCO/Vastar aver that "Dr. Parker's study provides direct, substantial evidence that (i) there is an active market for coalbed methane gas at the wellhead and (ii) coalbed methane is in marketable condition at the well. Id. ¶¶ 66-70." Petition at 2. ARCO/Vastar argue that Dr. Parker's study provides additional evidence that refutes MMS's determination when it previously analyzed this issue.

Dr. Parker's survey indicates that what he calls "substantial" volumes of coalbed gas are typically priced and sold at the wellhead. There are a number of flaws in his assertions. First, the identification of numerous coalbed gas transactions in which a producing entity sells or transfers to a wholly-owned or wholly-commonly-owned trading or marketing entity adds no relevant information about the marketability of untreated gas. Transfers between affiliates "at the wellhead" do not create a market for untreated gas or create contracts for the sale of gas that are "typical" for the field or area. ARCO/Vastar's argument would allow lessees to create a loophole that would swallow the market-

able condition rule by the simple device of inter-affiliate transfers.

Nor does the identification of numerous sales from unaffiliated operators to these larger marketing and trading entities prove that there is a broad "market" for untreated gas or that the "typical" contract is for untreated gas. Marketability is not determined solely by saleability. An unmarketable hydrocarbon product almost always can be sold for a lower price—one that allows the initial purchaser to recover the costs of treatment when the production is resold. Indeed, Dr. Parker's affidavit implicitly admits this. In paragraph 50 of his affidavit, he states:

> Sales transactions which take place at the well are generally structured so that the buyer pays the producer a price for gas at the well which is generally equal to the San Juan Index Price (or some percentage thereof) *less costs incurred by the buyer between the well and the interstate pipeline.* (Emphasis added.)

Those costs incurred between the well and the interstate pipeline include the cost of CO_2 removal. Sale-for-resale transactions thus are not particularly informative regarding the actual marketability of the product.

Dr. Parker's affidavit further states in paragraph 52:

> Recognizing the capacity constraints found in the existing conventional system and the inefficiencies involved in the commingling of coal seam gas [which he stated in paragraph 51 is high in CO_2 content] and conventional gas [which he admitted in paragraph 51 is low in CO_2 content] in conventional gathering and gas processing systems. *El Paso refused to accept the large volume of coal seam gas* beginning to come on line in this period. (Emphasis added.)

He then notes in paragraph 53 that "[o]ther entities immediately stepped into the vacuum created by El Paso's unwillingness to accept coal seam gas on its conventional gathering system." Specifically, he observes, two entities built facilities "to gather *and treat* the new, large volumes of Coal Seam Gas in preparation for the interstate pipelines and offered these field transportation and *treating services to others for a fee.*" (Emphasis added.) In short, Dr. Parker's assertions, taken together, show that the bulk of untreated coalbed methane that is high in CO_2 content effectively is unmarketable.

Marketability is determined in part by whether the production is satisfactory for use by those who ultimately purchase it for use. The affidavits document that the wellhead coalbed gas sold and actually used in the untreated condition is approximately 90.5 MMcfd or 6.3 percent of daily New Mexico coalbed gas production.[4] Thus, over 90

---

[4] The 90.5 MMcfd/6.3 percent was derived from figures provided by ARCO/Vastar with its SOR for the original appeal (*see* Exhibit 3 (Anderson Report), § III; Exhibit 4 (Edlund Affidavit), ¶ 4.a.-d.) and from the Petition (*see* Exhibit C (Mueller Affidavit). ¶¶ 54-59). This quantity does not include the volumes identified in these and related paragraphs where either the CO_2 content was five percent or less, *e.g.*, Red Cedar and Florida River systems gas (accounting for approximately 41.4 MMcfd or 2.9 percent), or the gas sales that were not specifically identified as gas used in its natural state with a high CO_2 content (*see, e.g.*, Exhibit B (Parker Affidavit), Exhibit ALP-13, Tbl. 1). The 90.5 MMcfd was compared to total New Mexico coalbed gas production of 1.435 MMcfd (*see* Exhibit B (Parker Affidavit), Exhibit ALP-13, Tbl. 1) rather than the 565 MMcfd used by Dr. Parker (*see Id.*) or the Val Verde Plant comparison of 800 MMcfd used in the Decision (*see Atlantic Richfield Co.*, MMS-97-0063-O&G, MMS-97-0191-O&G, 22 Gower Federal Service at 5, n.7, 7, n.9). Further, more than 75 MMcfd of the 90.5 MMcfd of untreated gas

percent of the daily New Mexico coalbed gas is treated for the removal of CO_2 and resold for use downstream. It was because the overwhelming percentage (90%) of coalbed gas is sold in a treated condition for the interstate market that the Assistant Secretary found that the gas at the wellhead is unmarketable without further basic treatment.[5] As determined by the Assistant Secretary, the amount of untreated wellhead sales is not "typical" within the meaning of the marketable condition regulation.

Much of Dr. Parker's affidavit actually consists of arguments against the marketable condition rule from a supposedly "economic" standpoint. While the views expressed are interesting, they are nevertheless contrary to settled law of gas valuation under Federal leases. The "marketable condition" rule has been uniformly sustained (*see e.g., Mesa Operating Ltd. Partnership v. Dep't of the Interior*, 931 F.2d 318 *reh'g denied* (5th Cir. 1991), *cert. denied*, 502 U.S. 1058 (1992)), and lessees must bear the costs of treatment to put production into marketable condition regardless of whether this particular affiant views untreated production as "marketable" in an "economic" sense. Further, ARCO/

---

consists of Amoco's and others' post-production field and area uses in processing, treatment, and transportation of the gas (derived from figures provided by ARCO/Vastar with its SOR for the original appeal (*see* Exhibit 3 (Anderson Report), § III; Exhibit 4 (Edlund Affidavit), ¶ 4.a.-d) and from the Petition (*see* Exhibit C (Mueller Affidavit). ¶¶ 54-59)). In other words, a vast majority of the high CO_2 content gas used in its natural state is for transportation, treatment, and processing of the coalbed gas that must occur in the field or area.

[5] *See Atlantic Richfield Co.*, MMS-97-0063-O&G, MMS-97-0191-O&G, 22 Gower Federal Service at 7 (failure to meet pipeline standard renders production unmarketable).

Vastar's reliance on the Interior Board of Land Appeals' (IBLA's) decision in *Xeno, Inc.*, 134 IBLA 172 (1995), is misplaced. In that case, the IBLA found evidence of a market for *ungathered* gas at the wellhead in view of competing offers from independent purchasers. The gas in that case was produced at sufficient pressure and without impurities (such as CO_2 or H_2S) that would require treatment for removal. The circumstances of the rather unique *Xeno* case are not apposite here.

Nor is ARCO/Vastar's reliance on the Colorado Court of Appeals' decision in *Rogers v. Westerman Farm Co.*, 986 P.2d 967 (Colo. App. 1998), *cert. granted*, 1999 Colo. LEXIS 868, well founded. First, that case does not involve CO_2 removal. Second, regardless of whether the Colorado Supreme Court ultimately agrees that the dehydration costs in that case are deductible under the private lease instruments involved in that case, dehydration is a cost necessary to put production into marketable condition as a matter of law applicable to Federal leases. As the preamble to the current Federal gas valuation regulations observes, "post-production costs for the services of gathering, separation, measurement, dehydration, compression, and sweetening are considered to be a requirement to place lease production into marketable condition, at no cost to the lessor." 53 Fed. Reg. 1230, 1267 (Jan. 15, 1988). *See e.g., Texas Co.*, 64 I.D. 76 (1957); *Placid Oil Co.*, 70 I.D. 438 (1963); *R.E. Yarbrough & Co.*, 122 IBLA 217, 221 (1993).

Conclusion

Based on the record, and for the reasons stated herein, the petition for reconsideration is denied.

Because this decision is issued by an Assistant Secretary of the Department of the Interior, it is not subject to appeal to the Interior Board of Land Appeals and is the final action of

the Department. *Blue Star, Inc.*, 41 IBLA 333 (1979); *Marathon Oil Co.*, 108 IBLA 177 (1989).

Sincerely,

/s/ Piet deWitt
Piet deWitt
Acting Assistant Secretary,
Land and Minerals
Management

APPENDIX E

[Seal Omitted]

United States Department of the Interior
OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

September 12, 2000

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Charles A. Breer
Davis, Graham & Stubbs LLP
Attorneys at Law
370 17th Street - Suite 4700
P.O. Box 185
Denver, Colorado 80201-0185

Re: MMS-97-0155-O&G
Amoco Production Company

Appeal Denied in Part; Order Modified

Dear Mr. Breer:

Amoco Production Company (Amoco, the Appellant) appealed under 30 CFR Part 290 (1997) from the Mineral Management Service's (MMS) order dated May 27, 1997 (Order), directing Amoco to pay additional royalties of $4,117,607 and to perform a restructured accounting for all San Juan Basin Federal and Indian leases producing coalbed methane for the period January 1989 through August 1996, and to pay any additional royalties due.[1]

---

[1] The audit period for the order to pay (January 1989-December 1996) differs from the period for the order to perform restructured accounting (January 1989-August 1996). Order at 1, 8. In addition, Amoco asserts that several of the "audited" leases are located in Colorado; even though the State's Issue Letter dated November 16,

The Order was based on an audit performed by the State of New Mexico in accordance with section 205 of the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA), 30 U.S.C. 1735 (1994). The New Mexico Taxation and Revenue Department (State) reviewed Amoco's royalty calculations[2] for coalbed methane produced from its Federal leases in the San Juan Basin.

Amoco's early coalbed gas sales occurred under conventional long-term gas contracts with El Paso Natural Gas Company (EPNG) at the wellhead, subject to EPNG's service fees for treating, gathering, compressing, transporting, and processing.[3] *See* Supplemental Statement of Reasons

---

1995, limited the "audit" to "Federal leases in the San Juan 30-6 Unit located in Rio Arriba County, San Juan Basin, New Mexico." Issue Letter at 1. Two of the non-New Mexico audited leases purportedly are Southern Ute Tribal Leases Nos. 519-000033-0 and 519-000034-0. SOR at 1. Karen Anderson, representing the Southern Ute Tribe (Tribe), informed MMS that these two leases are part of the Tribe's audit of Amoco in Docket No. MMS-97-0190-IND. These are the only Tribal (and non-New Mexico) leases identified by Amoco. By letter dated December 9, 1998, MMS retracted these two leases from the Order's requirement to perform a "restructured accounting." Although it appears that MMS's action was adequate to allay Amoco's "audit" concerns, all Tribal leases nonetheless are hereby excluded from the May 27, 1997, order and from this appeal. Further, this decision does not address any Indian oil and gas interests of the regulations governing those interests, particularly the valuation regulations that were amended and recodified during the audit period. *See* 61 F.R. 5467 (February 12, 1996).

[2] For Amoco's leases in the Northeast Blanco Unit, the unit operator, Blackwood & Nichols Co., reported and paid royalties on Amoco's behalf.

[3] Some of these early contracts were between EPNG and Tenneco Oil Co. or Pan American. Amoco subsequently acquired these properties.

(SSOR) at Exhibit C, Mueller Affidavit at ¶¶ 29-33. These contracts typically contained release or spot sale provisions, which allowed Amoco to sell to alternate buyers either at the wellhead or at downstream locations. *Id.* Amoco and EPNG agreed to an amendment in late 1989 that superceded all prior sales contracts, and provided for gas sales at the tailgate of one or more gas treatment plants in the area.[4] *Id.* at ¶ 34.

During the audit period, Amoco's coalbed methane was treated for the removal of Carbon dioxide (CO_2) in three plants: Meridian Oil Gathering Inc.'s (MOGI) Val Verde Plant, Williams Field Services' (WFS) Ignacio Gas Processing Plant, and WFS's Milagro Treating Facility. With respect to methane, CO_2 has no energy content and reduces the energy value per unit of volume of the gas stream of which it is a part. CO_2 may also combine with water vapor in a gas stream to form carbonic acid (H_2CO_3). In some circumstances, CO_2 is recovered and is sold as a valuable product—for example, for use in crude oil enhanced recovery operations—but that is not the case here.

The coalbed methane transported to and treated at MOGI's Val Verde Plant was produced primarily from the San Juan 30-6 Unit, Agreement No. 891-000538-A, during the audit period. Field Report (FR) at 2. The CO_2 content of the gas entering the Val Verde Plant ranged from 10.8 percent in December 1988 to 12.2 percent in December in 1995. Order at 5. The cost of CO_2 removal is $0.0778 per Mcf. The

---

[4] MOGI's Val Verde Plant and William Field Services' (WFS) Milagro Treating Facility are dedicated coalbed gas CO_2 removal plants. WFS's Ignacio Gas Processing Plant is a conventional gas processing plant used to separate liquefiable hydrocarbons from the natural gas stream as well as to remove CO_2.

transportation rate on the Val Verde "gathering system" to the plant is $0.3172 per Mcf from January 1989 through October 1990, and $0.2822 per Mcf from November 1990 through December 1996. *Id.* The gas leaves the Val Verde Plant and is marketed through EPNG's mainline transportation system. FR at 2.

The State audited Amoco's coalbed methane produced from the "30-8" Area and the Northeast Blanco Unit (NEBU), Agreement No. 892-000929-B, for the period May 1990 through December 1993. Order at 6; FR at 2. For the period February 1990 through June 1992, Amoco's production from those properties was processed in WFS's Ignacio Gas Processing Plant. Order at 6. The cost of services provided by WFS includes $0.1353 per Mcf for gathering, $0.0795 per Mcf for treating, and $0.0852 for transportation.[5] *Id.*

From July 1992 to December 1995, Amoco's coalbed methane entering the Mazanares System was treated in WFS's Milagro Treating Facility. *Id.* For NEBU production, the rates for WFS's gathering, treating, and transportation services based on Central Delivery Points (CDP's) are $0.26 for Simms Mesa CDP, and $0.30 for Pump Mesa

---

[5] The "Gathering and Treating Letter Agreement" dated February 13, 1990, contemplated that production from the Northeast Blanco Unit and "30-8" Area would enter Northwest Pipeline Company's (NWPL) mainline at the tailgate of WFS's Ignacio Gas Processing Plant, but would ultimately be redelivered to EPNG's mainline. The "Discounted Coal Seam Gathering, Treating, and Transportation Rates and Purchase Obligation" dated June 15, 1990, is the apparent result of WFS's failure to complete the tie-in to EPNG's mainline by the specified date. The amendatory agreement provided for WFS/NWPL to purchase the "30-8" area and Northeast Blanco Unit production until the EPNG interconnect was completed.

and Middle Mesa CDP's. *Id.* Because some gas from the NEBU was processed in the Val Verde Plant during this period, the costs of services for that plant were used for that gas. *Id.* The production transported on the Manzanares System was purchased by either WFS or Northwest Pipeline Company (NWPL) and delivered to EPNG's mainline for transportation downstream of the treatment facilities. *Id.*

Based on MMS's April 22, 1996, Dear Operator/Payor Letter, the State determined that Amoco incorrectly calculated gross proceeds for the coalbed methane sales resulting in royalty deficiencies of $4,117,607. The deficiency assessment consists of: 1) $432,158 for San Juan 30-6 Unit production for this period January 1989 through December 1996; 2) $1,308,372 for Northeast Blanco Unit (NEBU) production for the period January 1990 through December 1995); 3) $2,170,962 for other than NEBU Manzanares System production for the period July 1992 through December 1995; and 4) $206,115 for other than San Juan 30-6 Unit Val Verde production for the period October 1992 through December 1995. The MMS issued Amoco an order to pay that amount (FBIL 26974005). Further, MMS deemed Amoco's deficient royalty accounting to be systemic for all of its leases in the San Juan Basin producing coalbed methane.

Issues

I. Was CO_2 removal necessary to place the gas in marketable condition?

II. When coalbed gas is treated away from the lease, are the costs of transporting excess carbon dioxide (CO_2) deductible?

III. Does the April 22, 1996, Dear Operator/Payor Letter violate the Administrative Procedure Act?

IV. Can MMS collect royalties that become due more than six years before the date of the order to pay?

I. *Analysis - Removal of CO_2 was Necessary to Put the Gas into Marketable Condition*

Amoco argues that the only requirement under the marketable condition regulation is for the lessee to place gas in the physical condition necessary to market it under contracts *typical for the field or area.* Statement of Reasons (SOR) at 6 (emphasis in original); Supplemental Statement of Reasons (SSOR) at 8. Amoco asserts that the lessee is not required to condition the gas, *i.e.*, remove CO_2, for "downstream markets." In support of its position, Amoco cites *Beartooth Oil and Gas Co. v. Lujan*, CV 92-99-BLG-RWA, 7, 4-5 (D. Mont. 1993) *opinion withdrawn after remand and settlement*; *Marathon Oil Co. v. United States*, 604 F. Supp. 1375, 1386 (D. Alaska 1985), *aff'd*, 807 F.2d 759 (9th Cir. 1986), *cert. denied*, 480 U.S. 940 (1987); *Independent Petroleum Ass'n of America v. Armstrong*, 91 F. Supp. 2d 117, 125 (D.D.C. 2000); *California Co v. Udall*, 296 F.2d 384, 387 (D.C. Cir. 1961); and *Xeno, Inc.*, 134 IBLA 172, 182 (1995). SOR at 7; SSOR at 9. On this basis, Amoco asserts that the untreated coalbed methane—before removal of the CO_2—was in marketable condition.

Amoco's citations are largely misplaced. Neither *Marathon* nor the recent district court decision in *IPAA* involved questions of putting gas into marketable condition. The question in *Marathon* was whether MMS had properly calculated Marathon's gross proceeds as the landed sales price in Japan of the gas in liquefied form less the costs of transportation (liquefaction and tankering). (The District of Alaska and the Ninth Circuit both answered in the affirmative.) The issues in *IPAA* involved primarily the lessee's duty to market at no cost to the lessor. Treatment of gas to put it in marketable condition was not involved. *California Co. v. Udall* involved gathering, compression, and dehydration necessary to put gas into marketable condition, and lends no support to Amoco's theory.

In *Xeno* and *Beartooth*, it was necessary to examine when gas was in marketable condition—and, consequently, whether certain costs incurred were necessary to put gas into marketable condition or were undertaken for other purposes. The Interior Board of Land Appeals (IBLA) in *Xeno* found that the gas produced under the particular circumstances of that case was in marketable condition at a point before where MMS said it was in marketable condition, but that was a fact-specific finding. It does not answer the question of whether Amoco's untreated coalbed methane was already in marketable condition at the point of extraction. To answer that question, we must examine the circumstances of the instant case more closely.

For the period January 1989 to October 1990, Amoco states that gas produced from certain wells was sold at arm's length to Burlington Resources Oil & Gas Company (formerly Meridian Oil, Inc.) at the wellhead. SOR at 3. Amoco claims that the gas was sold at the wellhead in marketable condition at the prevailing market price in the area. SOR at 8. Several examples of wellhead sales of untreated coalbed methane are presented in an affidavit from Ms. Cristina Sigdestad.[6] *See* SOR at Exhibit C, Sigdestad Affidavit at & 4.

On May 1, 1990, Amoco entered into a contract to sell virtually all of its coalbed gas at the wellhead to Amoco

---

[6] Other wellhead sales are referenced in the Mueller affidavit. *See* SSOR at Exhibit C, Mueller Affidavit at ¶¶ 51-53, 55-57, 66-68. In addition, Amoco Energy Trading Co. (AETC) says it has over 50 third party contracts by which it purchases untreated coalbed gas at arm's length at the wellhead. *Id.* at ¶¶ 60-62. The Mueller affidavit also asserts that there is an active aggregator market at the wellhead. *Id.* at ¶¶ 63-65.

Energy Trading Co. (AETC).[7] *See* SSOR at Exhibit C, Mueller Affidavit at ¶ 39. The May 1990 contract provides for a price based on a calculated netback value. "AETC calculates the amount it owes Amoco by starting with the funds it receives from selling the gas to third parties,[8] and then subtracting any costs necessary to move the gas from the Delivery Point to the point where AETC sells the gas including costs to compress, dehydrate (away from the well), treat, and transport gas." The price calculation is similar to the manner in which Amoco determines value and pays MMS royalties. *Id.* at ¶ 41.

In further support of its argument that untreated coalbed gas is in marketable condition at the wellhead, Amoco provides affidavits[9] from Dr. Alfred L. Parker and Mr. Peter M. Mueller asserting that a significant and growing wellhead market exists for untreated coalbed gas in the San Juan Basin, and that the costs incurred downstream of the wells are for the purpose of enhancement of the gas for sale in secondary markets. SSOR at 4, 6-7.

In the Order, MMS asserts that the royalties paid on Amoco's coalbed methane production were based on a price that was reduced by the costs of gathering and treatment (primarily CO_2 removal). Order at 4, 7. The State calculated royalties for coalbed methane from the audited

---

[7] Amoco sells to AETC, its corporate affiliate, approximately 307,000 MMBtu of untreated coalbed gas per day.

[8] In the mid-1990's, approximately two-thirds of AETC's gas was aggregated and sold in the San Juan Basin "pools." The remainder was sold downstream of the San Juan Basin pools. *See* SSOR at Exhibit C. Mueller Affidavit at ¶ 49.

[9] *See generally* SSOR at Exhibits B and C, Parker and Mueller Affidavits.

leases by applying the valuation regulations in 30 CFR Part 206 (1989) and the guidelines contained in MMS's Royalty Policy Board letter of December 7, 1995. The MMS Order reflected these calculations. This Order said:

> By letter dated December 19, 1995, the State requested Amoco to provide a breakdown of costs associated with transporting the coalbed methane to a processing plant. Amoco's response was based on information received from Meridian by letter dated May 29, 1996, that indicated a cost of the CO_2 removal to be $.0778 per MCF.

Order at 4.[10]

The so-called "marketable condition rule" in the Federal gas valuation regulations provides:

> The lessee is required to place gas in marketable condition at no cost to the Federal Government or Indian lessor unless otherwise provided in the lease agreement. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition.

---

[10] The State's royalty calculations are far more complicated than the quoted passage implies due to multiple dispositions of coalbed methane production from the San Juan Basin. The costs of gathering and transportation are provided for the Val Verde and Manzanares Systems and the costs for treatment are provided for the Val Verde, Ignacio, and Milagro facilities. *See* Order at 5-7.

30 CFR 206.152(i) (1989).

Further, the regulations define marketable condition as "lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." 30 CFR 206.151 (1989).

The "marketable condition" rule has been uniformly upheld, and the lessee's obligation to put production into marketable condition at no cost to the lessor is uncontested. *E.g., Mesa Operating Limited Partnership v. Department of the Interior*, 931 F.2d 318 (5th Cir. 1991), *cert. denied*, 502 U.S. 1058 (1992); *California Co. v. Udall*, 296 F.2d 384 (D.C. Cir. 1961).

Whether untreated gas was sold under a contract that is typical for the field or area from which it is produced is pertinent to the valuation issue here. The demand for wellhead sales of untreated San Juan Basin coalbed gas that is utilized in that form is very limited and is not by any means the "typical" sales arrangement for that gas. Based on the volumes of each type of sale in the San Juan Basin, the dominant market for gas from the area is for the gas that is utilized in distant markets with a much lower CO_2 content.[11] As Amoco admits, "[A]lthough there is a market

---

[11] Excluding seasonal variations, Amoco documents a maximum of approximately 105 MMcfd of untreated coalbed methane sold at the wellhead and used by various entities in that form. Mueller Affidavit at ¶¶ 51-59, 66-68. Based on Burlington Resources Oil and Gas Company's (formerly Meridian Oil Inc.) and ARCO/Vastar's sales and purchases from the San Juan Basin, a maximum of approximately 60 MMcfd is untreated coalbed methane that is sold at the wellhead and utilized in that form. Together, these uses of untreated coalbed methane represent approximately 10 percent of total San Juan Basin coalbed methane production. Summation of figures found at page 2

for unprocessed coalbed gas at the well, *that wellhead demand is limited due to the lack of industrial and residential users in the San Juan Basin.* Consequently, much of the gas must be transported to distant users, . . ." SOR at 4 (emphasis added). Moreover, Amoco does not establish—and, indeed, does not even assert—that industrial and residential users could use untreated high-CO_2 content gas. Furthermore, although Amoco asserts that there could be an active end-user market for gas with CO_2 content great than 10 percent, such a market does not exist.

With the submittal of its SSOR, Amoco attempts to retreat from some of the statements it made. Amoco's arguments in its SSOR do not refer to what it previously (and correctly) characterized as a "limited" wellhead market for untreated coalbed gas. Amoco now talks in terms of a supposedly extensive and viable wellhead market. SSOR at 4. Further, the SSOR is supplemented with the assertions contained in the Parker and Mueller Affidavits.

The question requiring resolution is whether the production sold at the wellhead is in marketable condition prior to its subsequent treatment and transportation for use in distant markets. In other words, is the market at the wellhead the primary market for the gas as opposed to the more distant market?

---

of ARCO/Vastar's SSOR for MMS-97-0063-O&G (quoting Larry Anderson, "San Juan Basin Coalbed Gas Unique Regional Transportation Facilities" at 3.) and page 2 of the Edlund Affidavit of ARCO/Vastar's SSOR. *Atlantic Richfield Co.*, MMS-97-0063-O&G, MMS-97-0191-O&G (2000), 22 Gower Federal Service, Royalty Valuation and Management, Rocky Mtn. Min. L. Found. *Cf. infra* notes 17, 23.

Not only has the Department previously addressed the issue of removing only CO_2 in the marketable condition context,[12] the issue of acid gas removal has also been addressed.[13] In *Exxon*, IBLA stated that "it cannot be said that the transfer of title to the sour gas while it was still in its untreated condition meant that appellants were marketing untreated gas. . . . the fact that appellants bore the costs of sweetening meant that they were effectively marketing sweetened gas." *Exxon, U.S.A.*, 121 IBLA 234, 248-49 (1991).[14]

Here, two facts remain uncontroverted. One, the wellhead market for gas in an untreated condition is a limited "market" that is separate and distinct from the wellhead market for gas that is further treated; and two, Amoco is effectively marketing sweet gas by paying for the costs of treatment through a contractual pricing mechanism with AETC. Under these circumstances, IBLA's conclusion in *Texaco* that the value of production for royalty purposes cannot be reduced by the costs of sweetening applies.[15]

---

[12] *See Atlantic Richfield Co.*, MMS-97-0063-O&G, MMS-97-0191-O&G (2000), 22 Gower Federal Service, Royalty Valuation and Management, Rocky Mtn. Min. L. Found.

[13] *See Exxon Company U.S.A.*, 121 IBLA 234 (1991); *Apache Corp.*, 127 IBLA 125 (1993); *Texaco, Inc.*, Civ. No. 96-CV-08-J (D. Wyo. April 9, 1997).

[14] *See also Apache Corp.*, 127 IBLA 125, 134 (1993) (reducing royalty value by sweetening costs would amount to a subsidy by the Government equal to the royalty rate times those costs); *Texaco, Inc.*, Civ. No. 96-CV-08-J, slip op. at 5 (D. Wyo. April 9, 1997) (there is no market for sour gas if the seller pays to treat the gas, even though the purchaser accepts the gas untreated).

[15] "CIG's willingness to purchase Texaco's sour gas for a price which includes a reduction for CIG's costs of removing the hydrogen

Purchasers of gas from the field or area generally demand that the gas be properly conditioned for sale in the actual markets, which requires a lower CO_2 content. The fact that some purchasers are willing to purchase gas before conditioning and perform the conditioning themselves does not alter the finding that the gas requires conditioning. This is particularly true where the typical contracts for sales of gas from the field or area are in line with general national standards.[16] The Department of the Interior cannot allow producers simply to alter the form of their sales arrangements in order to force the lessor to share in the producers' costs to place the product in marketable condition.

Further, Amoco's contention that the treatment of coalbed gas constitutes enhancement of the gas has no merit. This simply an argument against the marketable condition rule and is contrary to established law.

---

sulfide from the gas does not establish that the sour gas was in marketable condition when it was sold to CIG or that the reduced price constitutes the reasonable market value of the production." *Texaco, Inc.*, 134 IBLA 109, 115 (1995).

[16] Amoco argues that its non-arm's-length sales of untreated coalbed gas to AETC are typical for the field. However, the coalbed gas in its natural wellhead state was never intended to be "marketed" but only sold on that basis. *See California Co.*, 296 F.2d at 388 (indicating the clear difference between marketing and selling). The market demand for the product is overwhelmingly conditioned gas free from excess CO_2. Thus, the predominant actual "market" consists of purchasers buying gas in a treated condition, not the artificial market created by resellers to avoid production-related costs of placing the gas in a marketable condition. The artificial nature of the purported market for untreated gas is obvious. Without the downstream market for treated gas, the sales of untreated gas would not have occurred due to lack of demand.

Here, there was limited demand for the product in the condition in which it was extracted at the wellhead. Consequently, the value for royalty purposes must be determined by adding to the gross proceeds received from the wellhead purchaser the cost of treating the gas for the removal of CO_2 to the level required to place the gas in marketable condition. Thus, the portion of the appeal claiming that the gas is in a marketable condition at the time of sale at the wellhead is denied.

Amoco also argues that MMS's requirement to condition the gas to an interstate pipeline standard of two percent (2%) CO_2 content is arbitrary and contrary to law. SOR at 8-11. In *California Co. v. Udall, supra*, the quality standard that established the marketable condition of the production was the standard required by the receiving pipeline because the wellhead gas sales contract specifically required the pipeline standard for production quality. Here, the gas must first meet the pipeline standard of quality before shipment to the market because the predominant market is not in the field or area. Therefore, transporting the production to a market outside the field or area is necessary to market the gas.

As discussed above, there is only a very limited use or sales of the gas in its wellhead condition. For a market to exist, there must be "an established demand for an identified product." *California Co. v. Udall*, 296 F.2d at 388. There is no evidence that a market exists for gas unless is it conditioned to meet the mainline specifications. Thus, the minimum required condition of the coalbed methane for marketing (and royalty) purposes is the quality required to supply the market(s) where the demand exists.

The MMS's regulations define marketable condition in terms of the quality requirements of a typical sales contract for the field or area.[17] 30 CFR 206.151. The mainline quality requirements are reflective of the required condition of the gas for sales of production from the field or area. If the production does not meet mainline specifications for transport to the downstream interconnect or end use, the production is effectively unusable. Accordingly, I find that the mainline transporters' CO_2 quality requirements

---

[17] Amoco's figures indicate that if all sources using Amoco's untreated coalbed gas were at maximum utilization (not factoring seasonal variations), they would comprise approximately 15.59 percent of Amoco's produced coalbed gas. Percentages derived from figures contained in Exhibit B, Mueller Affidavit at ¶¶ 51-59, 66-68. In *Atlantic Richfield Co.*, the record indicated that Burlington's and ARCO/Vastar's use, or sale of others' use, of untreated coalbed methane constituted less than 10 percent of the total coalbed methane entering the Val Verde Plant. Both *Atlantic Richfield Co.*, MMS-97-063-O&G, MMS-97-0191-O&G (2000), and the instant case concern the same field and area, the San Juan Basin during the same period (1989-1996). The percentages identified above the untreated coalbed methane used in that form in the field and area includes uses, or sales for others' uses, by Amoco, Vastar, and Burlington. Together these companies produce a substantial amount of the coalbed methane from the San Juan Basin. *See* RIK volumes volunteered in the companies' August 7, 1995, Royalty-in-Kind Onshore Pilot Program Agreement. Assuming *arguendo*, that the other San Juan Basin major producers' utilization, or sale of others' utilization, of untreated coalbed methane is marginally greater than that described above, the use of untreated coalbed methane would still not equal 20 percent of the total San Juan Basin coalbed methane produced. Thus, the sale of coalbed methane at the wellhead that is utilized in an untreated form does not constitute the "typical" sale of coalbed methane in the San Juan Basin.

effectively establish a marketable condition standard for gas sold from the field or area.

Based on the analysis above, this portion of the appeal is denied. However, the mainline quality standard (2% CO_2) used by the State in computing royalties does not agree with the mainline quality standards identified for the field and area for portions of the audit period (1 - 3% CO_2). The "Gathering and Treating Letter Agreement" dated February 13, 1990, states that "Williams shall provide sufficient treating to meet current EPNG specifications of one percent (1%) carbon dioxide." Letter Agreement at ¶ A. Although the quality of treatment required by EPNG is one percent (1%) CO_2 content, the gas that is sold to WFS/NWPL is transported in the NWPL mainline which specifies a three percent (3%) CO_2 content requirement. *See* NWPL tariff, Exhibit B to Letter Agreement. *See also Atlantic Richfield Co.*, MMS-97-0063-O&G, MMS-97-0191-O&G, (2000), 22 Gower Federal Service, note 10 (indicating evidence of different pipeline standards ranging from 1% - 3% of CO_2 content for the San Juan Basin field or area during the audit period).

Therefore, the Order is modified and the Appellant must recalculate the royalties due for the audited leases during the audit period based on the CO_2 content acceptable to the pipeline purchasers. The lessor will not share in treatment costs simply because one purchaser may require a marginally lower CO_2 content than another. Nor will the lessor require the lessee to condition the gas to a higher level of purity than the pipeline purchaser requires.

Summary

To summarize this section, the costs of removing CO_2 are the responsibility of the lessee when gas must be conditioned to meet the quality requirements typical for sales of gas from the field or area. Where there is no market for gas in the field or area, the marketable condition require-

ment is the quality of the mainline transportation to the downstream market. The actual mainline quality specifications shall be used in all instances, including any quality specifications that were "grandfathered." Thus, this portion of the appeal is denied and the Order is modified as explained above.

II. *Analysis - Amoco May Not Claim an Allowance for the Costs of Transporting CO_2 in Excess of Pipeline Specified Levels*

a. *Wellhead/CDP to Plant*

The MMS states in the Order that "[t]ransportation allowances are granted for the reasonable, actual necessary costs of transporting the coalbed methane from the royalty measurement point (either the well or the Central Delivery Point (CDP) [)] to the point of sale remote from the lease." Order at 2. Further, "no allowance may be taken for the costs of transporting lease production which is not royalty bearing without MMS approval." 30 CFR 206.157(a)(2)(i) (1989).

The transporters at or near the tailgates of the three CO_2 removal plants (*e.g.*, EPNG, NWPL, and Transwestern Pipeline Company) specify in their transportation agreements that the gas quality cannot exceed from one to three percent of CO_2 for mainline transport.[18] In addition, the

---

[18] "The record indicates that the mainline transporters' (El Paso Natural Gas, Transwestern, and Northwest Pipeline) CO_2 quality requirements vary from one to three percent (1-3%) content of coalbed methane volume over the audit period. SSOR at Exhibit No. 5. Further, El Paso Natural Gas 'grandfathered' the CO_2 allowed for mainline transportation from the Val Verde Plant at 2.13 percent. *Id.* (*see* Tariff No. 221 dated July 7, 1994)." *See Atlantic Richfield Co.*, MMS-97-0063-O&G, MMS-97-0191-O&G at 7, n. 10 (and accom-

guidance provided by MMS states that "transportation costs [can only be] allocated to the methane component for the amount of CO_2 permitted in the main (inter- or intrastate) transmission line." Dear Operator/Payor Letter at 2. Consequently, the State disallowed costs to transport CO_2 exceeding two percent (2%) of the combined volume of gas. Order at Schedules C, D, E, and F.[19]

Amoco argues that the State is restricting the allocation of transportation costs to gas that is at the interstate pipeline standard, and that the State considers CO_2 in excess of that standard a non-royalty bearing product. SOR at 12. Amoco contends that the cost of removing CO_2 should be included as part of the transportation allowance because unmarketable CO_2 is a waste product to which no allocation of transportation costs should apply in accordance with 30 CFR 206.157 (a) (2) (i) (1989). SOR at 12-14.

Further, Amoco states that the primary reason for removing the CO_2 is to transport the gas stream, not to place it in marketable condition. SOR at 14-15; SSOR at 7, 10, 12-13. Amoco avers that removal of the CO_2 enhances the value of the production for downstream sales. Consequently, Amoco believes that an allowance for the cost of enhancement should be available as a deduction from the downstream

---

panying text). For the instant case, the producing basin, the mainline transporters and the audit period are virtually the same.

[19] There is no explanation why two percent CO_2 content is used for royalty purposes rather than the specified requirements of one percent (1%) CO_2 content for EPNG as recognized in the Gathering and Treating Letter Agreement. Letter Agreement at 1. Also, Article 14 of the Gathering and Treating Letter Agreement provides for Amoco to deliver coal seam gas at NWPL's quality specifications (3% CO_2). *See* Letter Agreement at Exhibit B, § 3.1(c).

value of the gas for royalty purposes. SSOR at 3, 10, 12-13. Amoco concludes that CO_2 removal should be treated the same as the dehydration costs in *Exxon*, 118 IBLA 221, 240, 250, and the liquefaction costs in *Marathon Oil Co. v. United States*, 604 F. Supp. at 1375, 1381-86 (D. Alaska 1985), *aff'd*, 807 F.2d 759 (9th Cir. 1986), *cert. denied*, 480 U.S. 940 (1987), and because of its enhancement capacity, should not be subject to royalty as detailed in *Xeno, Inc.*, 134 IBLA at 180, 183-84, and *IPAA*, 91 F. Supp. 2d at 120, 125. SOR at 14-15; SSOR at 3, 9-13. I disagree with the Appellant's contentions.

For the audit period, the record is unclear regarding whether all of Amoco's gas was sold at the wellhead.[20] When

---

[20] The only sales agreement included in the record is the Discounted Coal Seam Gathering, Treating, and Transportation Rates and Purchase Obligation dated June 15, 1990. This agreement provides only for the temporary purchase of the "30-8" and Sims Mesa area production (also known as Ignacio Plant volume reduction) until such time that the WFS Interconnect is completed with the EPNG mainline. Also, Amoco alludes to an arm's-length wellhead sale to the Burlington Resources Oil and Gas Company (formerly Meridian Oil, Inc.) for the period January 1989 through October 1990. However, Amoco's SSOR contains descriptions of Amoco's wellhead sales contracts (2) with Burlington Resources and Amoco's wellhead purchase contracts (54) with various third parties, as well as descriptions of numerous wellhead sales contracts between various parties in the San Juan Basin. SSOR at Parker Affidavit, Exhibits ALP-8 and ALP-10. Prior to 1989, most of Amoco's San Juan Basin production was sold at the wellhead to El Paso Natural Gas Pipeline. SSOR at Exhibit B, Mueller Affidavit at ¶¶ 29-34. Commencing in 1990, Amoco sold virtually all of its coalbed gas that is produces form the San Juan Basin to AETC at the wellhead. Id. at ¶¶ 39-41. Amoco's other wellhead dispositions of coalbed gas are also discussed. Id. at ¶¶ 48-68.

valuing production that is sold at arm's length at the wellhead under 30 CFR Part 206, the cost of transportation downstream of the wellhead is not a factor and there is no transportation allowance.

The State argues that since a rate per Mcf is charged AETC for transporting the entire coalbed gas stream, the portion of the fee applicable to the CO_2 content in excess of the mainline allowable cannot be ignored for royalty purposes. Therefore, because payments to Amoco for gas sales under Unit Operating Agreements/Joint Operating Agreements or any other contract at the wellhead/CDP reflects a reduction for the costs of gathering, treating, and transporting the coalbed methane, those costs must be added back into the payment received by Amoco to determine the value of production for royalty purposes.

When coalbed methane is sold arm's length at the wellhead, the cost of transportation downstream of the point of sale would not be deducted separately as an allowance under 30 CFR 206.156 and 206.157 (1989). Similarly, for all production sold at the wellhead of CDP's for the remainder of the audit period, there is no transportation allowance for royalty valuation purposes. The addition of the costs of transporting the CO_2 component above the mainline standards to the lessee's wellhead gross proceeds is warranted in this situation because to do otherwise would have the lessor share in costs that it would not otherwise share in simply by the vehicle chosen by the lessee in selling its production.[21]

---

[21] Amoco receives a price for gas from AETC that is AETC's arm's-length proceeds from third parties net of costs of gathering, treating, and transporting the gas to the point of sale. *See* SSOR at Exhibit C, Mueller Affidavit at ¶ 41. The State argues that the net price received by Amoco must be adjusted by adding back in all costs

Amoco misconstrues the decision in *IPAA* in arguing that the removal of CO_2 is an enhancement process for the sale of production in secondary markets. As determined in Section I, above, the removal of CO_2 is necessary to put production into marketable condition. Thus, the conclusion in *IPAA* that MMS does not have "the authority to define value to include downstream costs unrelated to production of the gas" does not apply here.[22]

---

associated with placing the gas in marketable condition (*e.g.*, costs of gathering and treat the coalbed gas), and transportation of CO_2 in excess of the mainline allowable. Thus, the State perceives the valuation issue to be one in which the lessee has failed to place the gas in a marketable condition at no cost to the lessor. In the instant case, AETC (the purchaser), assuming the lessee's marketable condition duty, is a wholly-commonly-owned affiliate of the lessee. If the proceeds received by the wholly-commonly-owned affiliate minus applicable transportation costs (not including excess CO_2 transportation) were used for royalty valuation purposes, the result presumably would be the same as that now sought by the State given the AETC/Amoco pricing arrangement described above. However, the State did not examine AETC's resale proceeds, and we therefore, do not address the issue of the wholly-commonly-owned affiliate's resale proceeds in this decision.

[22] *See IPAA*, 91 F. Supp. 2d at 125.

The fact that a producer can sell relatively small volumes[23] of coalbed gas in an untreated condition does not make the gas, most of which must be treated for downstream sale, marketable in an untreated condition. The decision in *IPAA* did not address costs necessary to put production into marketable condition and did not affect the non-deductibility of those costs.

b. *Post-Plant Sales*

For all gas that is sold downstream of the wellhead or CDP, a transportation allowance may be applicable. However, evidence of the post-treatment selling arrangements is not contained in the record. For any of these sales of coalbed methane that occur, the regulations at 30 CFR 206.156 and 206.157 (1989) govern applicable transportation allowances, subject to the determination in II.c. below.

c. *Transportation of Waste*

Amoco argues that the State incorrectly computes the allowable costs of CO_2 transportation both from the wellhead/CDP to the plant and from the plant to the point of

---

[23] Amoco's figures indicate that if all sources using Amoco's untreated coalbed gas were at maximum utilization (not factoring seasonal variations), they would comprise approximately 15.59 percent of Amoco's produced coalbed gas. Percentages derived from figures in Exhibit B, Mueller Affidavit at ¶¶ 51-59, 66-68. However, in accordance with the State's analysis, "less than one tenth of one percent of the *total* coalseam production . . . is sold and truly valued with the carbon dioxide entrained in the gas stream." State's Response to Amoco's SSOR at 4. Six treatment plants in the San Juan Basin typically treat coalbed methane gas, Val Verde, Milagro, Arkansas Loop, Florida River, La Maquina, and Esparanza. MMS October 1995, "Coalbed Methane Royalty Issues." However, coalbed methane may also flow to and through or bypass other plants in the San Juan Basin, *e.g.*, Blanco, San Juan, and Ignacio.

sale. Amoco contends that allocation to the methane stream of the costs of transporting a CO_2 waste product comports with the valuation regulations and that there is no reason for treating amounts of "waste" CO_2 within interstate pipeline standards, i.e., less than two percent, differently than amounts in excess of those standards. Finally, Amoco argues that is arbitrary for MMS to allow a deduction for two percent of CO_2 content, but not for the amount of CO_2 content at issue here. SOR at 12-14. I disagree.

The issue of transporting CO_2 in excess of the mainline quality standard downstream of the plants has already been addressed, in effect, by the marketable condition determination in section I. above. In other words, because the coalbed methane must be placed in a marketable condition prior to mainline transport, there are no CO_2 volumes that must otherwise be transported downstream of the plant. Thus, the sole issue regarding CO_2 waste volumes pertains to the transportation of the coalbed methane from the wellhead/CDP to the processing/treatment plants.

The guidance by the *Payor Handbook* notes that "[t]ransportation costs for a gaseous stream [or a liquid and gaseous stream] are allocated only to the royalty-bearing and non-royalty-bearing products. For transportation cost allocation purposes, a waste product is considered neither royalty-bearing nor non-royalty bearing. Therefore, the waste product volume is excluded from the cost allocation." *Payor Handbook* 6.4.1.

The three examples contained in section 6.4 of the *Payor Handbook* all assume that CO_2 is a waste product. Additional guidance is contained in the April 22, 1996, Dear Operator/Payor Letter. In assessing additional royalties on Amoco for transportation of CO_2 volumes, MMS followed the guidance in the Dear Operator/Payor Letter, which states:

> For coalbed methane production, you can increase the transportation costs allocated to the methane component for the amount of CO_2 permitted in the main (inter- or intrastate) transmission line. For example, if your gas stream consists of 90 percent methane and 10 percent CO_2 and the main transmission line allows 2 percent CO_2 in the makeup of its gas stream you can include the costs of transporting the 2 percent CO_2 volume (or 92 percent of the total transportation cost) when calculating your allowance for methane.

Dear Operator/Payor Letter at 2.[24]

The valuation regulations address waste as follows:

> [T]he total transportation costs shall be allocated in a consistent and equitable manner to each of the products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, no allowance may be taken for costs of transporting lease production which is not royalty bearing.

30 CFR 206.157 (a) (2) (i); 206.157 (b) (3) (i).

The preamble to the revised valuation regulations published in the *Federal Register* on January 15, 1988, provides:

> The MMS does not agree with the commenter's proposal that the cost of the transporting nonroyalty-

---

[24] A Dear Payor Letter issued February 4, 1988, also addresses transportation cost allocation among products, but it does not contain the CO_2 instructions issued in the April 22, 1996, Dear Operator/Payor Letter.

> bearing substances should be shared by the lessor in all instances. However, upon review, MMS has recognized that it is appropriate to provide an allowance which includes the costs of transporting certain non-royalty-bearing substances such as waste products, including water. For example, there may be circumstances where transportation of water along with the royalty-bearing portion of the production is necessary. For other than waste products, the final rule provides, however, that prior MMS approval is required before an allowance may be taken for the costs of transporting non-royalty-bearing substances.

53 F.R. 1230, 1258 (1988).

The regulations do not specifically explain the distinction between "non-royalty-bearing products" and "waste products." The guidance provided in the Dear Operator/Payor Letter treats CO_2 as a non-royalty-bearing product, but then directs the operator/payor to "use the regulation in 30 CFR 206.156 and 206.157 (1995) and the instructions in Chapter 6 of the *Oil and Gas Payor Handbook*, Volume III, to calculate your transportation allowance."

Arguably, one could infer from the *Payor Handbook* hypotheticals that CO_2 in this situation is assumed to be a "waste product." To do so, however, would be incorrect.[25]

---

[25] The Payor Handbook examples at 6.4.1, 6.4.2, and 6.4.3, contain unfortunate ambiguities. They refer to gas streams that have MMBtu measures of CO_2 and helium. Neither CO_2 nor helium have energy contents (Btu's). Thus, the hypothetical examples are difficult to apply because we have no idea of the volumes of these gas stream constituents upon which to compute transportation allowances.

The intent of the *Payor Handbook* examples is apparent. Proportionate measures of the identified gas stream constituents affect the computation of transportation allowances. Had the numbers given in the examples represented volumes instead of Btu's, the results would have been what MMS intended. Then, the reference to CO_2 as a waste product would have made sense with respect to the regulations.

The MMS allocates the cost of transporting the mainline allowance non-methane constituents in a gas stream to the methane component. This is the only portion of non-royalty-bearing production that is considered a waste product. Even if the *Payor Handbook* examples, the fraction of CO_2 in the examples represented typical mainline allowables; representing from one to two-and-one-half percent (1-2½%) of the heating value (sic) of the gas stream.

The Dear Operator/Payor Letter guidance primarily treats the CO_2 content that was removed from the coalbed methane as a non-royalty-bearing product. Only the pipeline allowable CO_2 content (remaining in the methane stream) is treated as a waste product.[26] Beyond a point, pipeline tolerances[27] dictate against further removal of impurities, which then become a waste product (as opposed to its non-royalty-bearing status if present in amounts greater than the quality specifications of the mainline).

The valuation regulations specify that transportation costs are to be allocated to all royalty-bearing products after ex-

---

[26] The cost to transport the interstate pipeline allowable CO_2 content is allocated to the methane and allowed as a cost of transporting the methane. *See* Dear Operator/Payor Letter at 2.

[27] Pipeline tolerance used in this context refer to the physical ability of the pipeline to operate efficiently at certain levels of non-methane constituents or contaminants.

cluding waste products, both from the total volume and from the volume of all products. 30 CFR 206.157 (a) (2) (i); 206.157 (b) (3) (i). In addition, the preamble providing the rationale for these regulations clearly indicates that the cost to transport non-royalty-bearing products that are not waste products will not be included in the allowable transportation deduction for royalty-bearing products. 53 F.R. 1230, 1258 (1988). The preamble implication that MMS will approve an allowance for the costs to transport non-royalty-bearing substances is limited to those non-royalty-bearing substances that are also waste products as defined above. *Id.*

Here, the CO_2 produced in conjunction with the methane from the coalbed is transported to a processing/treatment plant, separated (save for approximately two percent content) from the methane, and vented. There is no market for this CO_2. The intent of MMS's regulations and *Payor Handbook* is that waste production for the purpose of determining allowable transportation costs is the fraction of non-royalty-bearing production that is allowable in a mainline transportation system. In the instant case, all CO_2 in excess of the mainline standard is non-royalty-bearing production. Therefore, this portion of the appeal is denied.

Consistent with the modification in section I. above, the mainline standard of allowable CO_2 (2% CO_2) used by the State in computing royalties does not agree with the mainline quality standards identified in the record for portions of the audit period (1-3% CO_2).[28] Therefore, the Order is modified and the Appellant must recalculate the royalties

---

[28] *See supra* note 18.

due for the audited leases during the audit period based on the guidance above.

III. *Analysis - The April 22, 1996, Dear Operator/Payor Letter Does Not Violate the Administrative Procedure Act*

Amoco avers that the State is applying the April 22, 1996, Dear Operator/Payor Letter as a rule in violation of the Administrative Procedure Act (APA). 5 U.S.C. 551-559, 701-706 (1994). In support of its position, the Appellant cites *Phillips Petroleum Co. v. Johnson*, 22 F.3d 616 (5th Cir. 1994), *modified on other grounds*, 1994 WL 484506, *cert. denied*, 514 U.S. 1092 (1995). Under *Phillips*, the court determined that APA required notice and comment rulemaking for the valuation procedures at issue in that case. In addition, Amoco argues that the supposedly newly instituted procedures cannot be applied retroactively. SOR at 16.

Here, the State applied the existing valuation regulations which were further explained by the April 22, 1996, Dear Operator/Payor Letter. To the extent that the State's interpretation was inconsistent with the regulations, this decision modifies the Order to make it consistent with the regulations.

When, through notices of interpretive rules, the Government explains and clarifies existing regulations, the procedural requirements of formal rulemaking under the Administrative Procedure Act, 5 U.S.C. 553 (1982), are not applicable. *Venlease I*, 99 IBLA 387 (1987). *See Shalala v. Guernsey Memorial Hospital*, 514 U.S. 87, 115 S.Ct. 1232 (1995). The Dear Operator/Payor Letter is an interpretation of existing regulations. Therefore, this portion of the appeal is denied.

IV. *Analysis – The Statutory Bar is Inapplicable to Administrative Appeals*

Amoco argues that any part of MMS's demand seeking royalties that accrued more than six years prior to the

demand is barred by the six-year statute of limitations in accordance with 28 U.S.C. 2415 (1994). However, rather than develop an argument on this issue, Amoco preserved this issue for use on the event of a further appeal. SOR at 16-17.

This proceeding is an administrative appeal and the statutory bar is inapplicable. *Foote Mineral Co.*, 34 IBLA 285, 306 (1978); *Anadarko Petroleum Corp.*, 122 IBLA 141 (1992). Therefore, the Appellant's claims with respect to the statute of limitations are without merit and this portion of the appeal is denied.

Conclusion

I. Was the cost of CO_2 removal necessary to place the gas in marketable condition?

The gas was not in marketable condition for its object market. The cost to place the production into marketable condition is to be borne by the lessee at no cost to the lessor. Thus, the proceeds received at the wellhead/CDP for gas must be increased by the cost of placing the gas in marketable condition. The removal of CO_2 from the coalbed gas stream is required to place the gas in marketable condition. Costs to place gas in marketable condition do not qualify as costs of processing.

II. When coalbed is treated away from the lease, are the costs of transporting excess carbon dioxide (CO_2) deductible?

When the gas is sold at the wellhead, no transportation costs are allowed to be deducted from the value of production for royalty purposes. Costs to transport non-royalty-bearing production to enable the production to be placed in a marketable condition are not allowed, except to the extent that the mainline transporter allows a specified amount.

When the lessee transports gas from the lease to a point of sale away from the lease, the cost to transport the gas may

be allowable. The cost to transport gas is not allocable to waste products, but is allocable to royalty-bearing and non-royalty-bearing, non-waste production. The portion of the cost allocated to non-royalty-bearing products is not deductible as an allowance. Waste is defined as the mainline allowable portion of a particular non-methane constituent of the gas.

III. Does the April 22, 1996, Dear Operator/Payor Letter violate the Administrative Procedure Act?

The Dear Operator/Payor Letter is an interpretive guide to existing regulations. Thus, the procedure contained in the Dear Operator/Payor Letter does not violate the Administrative Procedure Act.

IV. Can MMS collect royalties that are more than six years past due?

Because the statutory bar is inapplicable to administrative appeals, 28 U.S.C. 2415 has not been violated.

Amoco must recalculate the royalties due accordingly.

Because this decision is issued by an Assistant Secretary of the Department of the Interior, it is not subject to appeal to the Interior Board of Land Appeals and is the final action of the Department. *Blue Star, Inc.*, 41 IBLA 333 (1979); *Marathon Oil Co.*, 108 IBLA 177 (1989).

/s/ Sylvia V. Baca
Sylvia V. Baca
Assistant Secretary, Land
and Minerals Management

Enclosure

APPENDIX F

[Seal Omitted]

United States Department of the Interior

OFFICE OF THE SECRETARY

WASHINGTON, D.C. 20240

March 24, 2000

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Norma J. Rosner
Associate General Counsel
Vastar Resources, Inc.
15375 Memorial Drive
Houston, Texas 77079

Re: MMS-97-0063-O&G
MMS-97-0191-O&G
Atlantic Richfield Company
Vastar Resources, Inc.

Appeal Denied in Part;
Order Modified

Dear Ms. Rosner:

Atlantic Richfield Company (ARCO/Vastar, the Appellant)[1] appealed under 30 CFR Part 290 (1997) from the Minerals Management Service's (MMS) order dated January 22, 1997 (Order), directing ARCO/Vastar to pay additional royalties of $782,373 and to perform a restructured accounting for all San Juan Basin Federal and Indian leases producing coalbed methane that is transported and processed through the Val Verde System for the period January 1989 through August 1996 (audit period), and to pay any

[1] The January 22, 1997, Order relates to properties that were assigned by ARCO to its subsidiary, Vastar Resources, Inc. (Vastar). However, since the Order may affect other property and interests retained by ARCO, ARCO and Vastar are jointly responding to the Order.

additional royalties due.[2] ARCO/Vastar's appeal of the Order was assigned docket No. MMS-97-0063-O&G. ARCO/Vastar also appealed an MMS. Royalty Valuation Division (RVD), decision dated July 14, 1997 (RVD Decision), concerning some of the same leases and issues as the Order. The MMS assigned docket No. MMS-97-0191-O&G to ARCO/Vastar's appeal of the RVD Decision.

The Order was based on an audit performed by the State of New Mexico in accordance with section 205 of the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA), 30 U.S.C. 1735 (1994). The New Mexico Taxation and Revenue Department (State) reviewed ARCO's royalty calculations for coalbed methane produced from its leases in the San Juan No. 30-6 Unit (audited leases).[3] Prior to April 1992, the coalbed methane produced from this unit was sold arm's-length at the wellhead before it was transported through Meridian Oil Gathering Inc.'s (MOGI) Val Verde System to the Val Verde Plant for removal of carbon dioxide (CO_2). Although the production continued to be treated in the Val Verde Plant after March 1992, the gas was sold under various selling arrangements downstream of the plant.

---

[2] The restructured accounting order provides that all Federal and Indian leases must be reviewed. Based on a June 10, 1998, telephone conversation with Norma Rosner, Associate General Counsel, Vastar, neither ARCO nor Vastar have any interest in Indian leases producing coalbed methane that is transported and processed through the Val Verde System during the audit period. Therefore, this decision does not address Indian oil and gas interests or the regulations governing those interests, particularly the valuation regulations that were amended and recodified during the audit period. *See* 61 F.R. 5467 (February 12, 1996).

[3] MMS Unit No. 891-000538-A leases for which ARCO is the lessee are Leases Nos. 029-003385-0, 029-003403-0, 082-080711-0, and 082-080712-0. Also, numerous non-ARCO leases are committed to this unit.

Based on MMS's April 22, 1996, Dear Operator/Payor letter, the State determined that ARCO incorrectly calculated gross proceeds for the coalbed methane sales resulting in royalty deficiencies of $782,373 (FBIL 26974003). Further, MMS deemed ARCO's deficient royalty accounting to be systemic for all leases for which coalbed methane gas is transported through the Val Verde System and processed in the Val Verde Plant.

In the RVD Decision, RVD determined that the removal of CO_2 from coalbed methane produced from the San Juan Basin does not qualify for an extraordinary processing cost allowance in accordance with 30 CFR 206.158(d)(2)(1) (1989). The coalbed methane is transported and treated in the Val Verde Plant. ARCO/Vastar is charged a fee of $0.0778 per Mcf for CO_2 removal. All CO_2 removed in the Val Verde Plant during the audit period was vented to the atmosphere.

The issues of marketable condition and extraordinary processing cost allowances are identical for some of the leases in both the Order and the RVD Decision.[4] For other ARCO/Vastar leases, these issues are substantially similar and cover the same period and field and area. Therefore, the appeals from the Order and from the RVD Decision are consolidated.

The issues other than marketable condition and extraordinary gas processing cost allowances that are listed below are exclusive to gas produced form leases subject to the Order. All references to the Appellant's Statement of Reasons (SOR), Supplemental Statement of Reasons (SSOR), and Field Report (FR) responses cited in this decision are directed to the issues raised by the Order, unless otherwise specifically noted.

---

[4] ARCO/Vastar's Leases Nos. 029-003385-0, 029-003403-0, 052-060711-0, and 082-080712-0 appear in both the Order and the RVD Decision.

Issues

1. Was the cost of CO_2 removal:

a.) necessary to place the gas in marketable condition, or b.) allowable as an extraordinary processing cost allowance?

2. Are costs incurred to transport the coalbed methane deductible?

3. Does the April 22, 1996, Dear Operator/Payor Letter violate the Administrative Procedure Act?

4. Is late payment interest applicable to royalties deemed deficient for prior periods?

1. *Analysis - CO_2 Removal*

a. Marketable Condition

ARCO/Vastar argues that the only requirement under the marketable condition regulation is for the lessee to place production in the physical condition necessary to market it under contracts typical for the field or area. SSOR at 10. Thus, ARCO/Vastar believes that the lessee is not required to condition the gas, i.e., remove CO_2 for "downstream markets." ARCO/Vastar cites *Beartooth Oil and Gas Co. v. Lujan*, CV 92-99-BLG-RWA (D. Mont. 1993), slip op. at 6 (opinion withdrawn after remand and settlement), in support of its position. *Id.*

For the period January 1989 through March 1992, ARCO/Vastar states that gas produced from the audited leases was sold arm's-length to Meridian Oil Inc. (Meridian) under the Unit Operating Agreement.[5] ARCO/Vastar claims that the gas was sold at the wellhead in marketable condition at the prevailing market price in the area. SSOR at 10. Several examples of wellhead sales of untreated coalbed methane are presented in an affidavit from Mr.

---

[5] Unit Operating Agreement, San Juan 30-6 Unit area, between El Paso Natural Gas Company (Unit Operator) and various parties owning working interests in the unit.

Peter Edlund. *See* SSOR, Exhibit 4 at 2. "Since March 1992, ARCO has marketed their [sic] production under various selling arrangements." Order at 5. ARCO/Vastar cites *Xeno Inc.*, 134 IBLA 172 (1995), in support of its position that the production is in marketable condition at the wellhead. SSOR at 15.

As a corollary to the marketable condition issue, ARCO/Vastar avers that requiring royalty payment based on an arm's-length contract value increased by costs to place production in a downstream marketable condition violates the gross proceeds rule. ARCO/Vastar insists that the State cannot establish a value of the enhanced gas after post-sale transportation and CO_2 removal without taking into account allowable transportation and/or processing deductions. SSOR at 15.

In the Order, MMS asserts that the price received for wellhead production from January 1989 through March 1992 was derived from a wellhead sale from ARCO/Vastar to Meridian Oil Trading Inc., Meridian's affiliate. Based on third party information, the State determined that the wellhead prices offered by Meridian were reduced by costs associated with transporting the gas, and the processing to remove the CO_2 from the gas stream. Order at 5.

The State calculated royalties for coalbed methane from the audited leases by applying the valuation regulations in 30 CFR Part 206 (1989) and the guidelines contained in MMS's December 7, 1995, Royalty Policy Board Letter[6] as follows:

> On January 8, 1996, the State requested ARCO to provide a breakdown of costs associated with transporting the coalbed methane gas to the processing plant, any costs of dehydration prior to the CDP

---

[6] The Royalty Policy Board Letter formed the internal basis for the subsequent April 22, 1996, Dear Operator/Payor Letter, which provided public guidance for valuing coalbed methane.

> [Central Delivery Point] and after the CDP, any costs associated with compression incurred to enhance production, or any compression necessary to move the gas to the processing plant, and costs associated with the removal of the CO_2 from the gas stream. ARCO's response to the State's request, was based on information received from Meridian by letter dated May 9, 1996, [which] stated the cost off [sic] the CO_2 removal was $.0778 per MCF.

Order at 5.

The Federal and Indian oil and gas valuation regulation's marketable condition rule provides as follows:

> The lessee is required to place gas in marketable condition at no cost to the Federal Government or Indian lessor unless otherwise provided in the lease agreement. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition.

30 CFR 206.152(i) (1989).

The regulations define marketable condition as "lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." 30 CFR 206.151 (1989). Whether the gas was sold under a contract that is typical for the field or area from which it is produced is pertinent to the valuation issue here. Although ARCO/Vastar identifies several nominal sales of untreated coalbed methane for use in the area without

removal of the CO_2 (SSOR at 3-4), the dominant market for gas from the area is for gas with a lower CO_2 content.[7]

As ARCO/Vastar states, "[d]espite the active market for coalbed gas at the well, the total wellhead demand is limited by the lack of residential and industrial users in the region in which the field is located. Consequently, much of the gas must be transported to distant users . . . ." SSOR at 4. Furthermore, although ARCO/Vastar asserts that there could be an active end-user market for gas with a CO_2 content greater than 10 percent, such a market currently does not exist.[8]

Purchasers of gas from the field or area generally demand that the gas be properly conditioned for sale in the actual markets, which requires a lower CO_2 content. The fact that some purchasers are willing to purchase gas prior to conditioning and perform the conditioning themselves does not alter the finding that the gas needs to be conditioned. This is particularly true where the typical contracts for sales of gas from the field or area are in line with general national standards. The Department of the Interior cannot allow producers simply to alter the form of their sales arrangements in order to force the lessor to share in the producers' costs to place the product in marketable condition.

In *California Co. v. Udall*, 296 F.2d 384, 386 (D.C. Cir. 1961), the wellhead sales contract between The California Company and Southern Natural Gas Company required that the gas meet the quality and pressure specifications of

---

[7] Based on the relatively current sales and utilization of gas in the field and area, gas with high CO_2 content (untreated) consists of less than 10 percent of Val Verde Plant capacity. (Derived from figures found at page 2 of the Edlund Affidavit.)

[8] ARCO/Vastar's arguments as to why pipeline transporters using tariffs based on energy content prefer not to transport gas with a high CO_2 content would apply equally to local distribution companies in distant markets.

the receiving pipeline. Consequently, the Department of the Interior disallowed the expenditures required to condition the gas to meet the pipeline specifications as production costs required to place the gas in marketable condition. *Id.* The court determined that the Secretary did not abuse his discretion by defining the statutory term "production" (for royalty purposes) as gas that is readied for the market into which it is sold. *Id.* at 388.

Here, there was little or no actual demand for the production in the condition extracted at the wellhead. Consequently, the value for royalty purposes must be determined by adding to the gross proceeds received from the wellhead purchaser the cost of treating the gas by the removal of CO_2 to the level required to place the gas in marketable condition. Thus, the portion of the appeal claiming that the gas is in a marketable condition at the time of sale at the wellhead is denied.

ARCO/Vastar lso argues that MMS's requirement to condition the gas to an interstate pipeline standard of two percent (2%) CO_2 content is arbitrary and contrary to law. SSOR at 11-13. I find that the mainline transporters' CO_2 quality requirements effectively establish a marketable condition standard for gas sold from the field or area.

In *California Co. v. Udall,* the quality standard that established the marketable condition of the production was the standard required by the receiving pipeline because the wellhead gas sales contract specifically required the pipeline standard for production quality.

Here, the gas must first meet the pipeline standard of quality before shipment to the market due to the absence of a viable market in the field or area. Therefore, the transportation of the production to a market outside the field or area is an integral part of marketing the gas.

There is only a very limited market for the gas in its wellhead condition. For a market to truly exist, there must

be "an established demand for an identified product." *California Co. v. Udall*, 296 F.2d at 388. There is no evidence that a market exists for the gas at issue unless it is conditioned to meet the mainline specifications. Thus, the minimum required condition of the coalbed methane for marketing (and royalty) purposes is the quality required to supply the market(s) where the demand exists.

The fact that ARCO/Vastar included a copy of the Southern California Gas Company tariff for transporting customer-owned gas to end users evidencing a marginally higher permitted CO_2 content (3%) than the current mainline requirements is of little import. MMS's regulations define marketable condition in terms of typical sales contract quality requirements for the field and area.[9] 30 CFR 206.151. The mainline quality requirements are reflective of the required condition of the gas for sales of production from the field or area. If the production does not meet mainline specifications for transport to the downstream interconnect or end use, the production is effectively unusable.

Based on the analysis above, this portion of the appeal is denied. However, the mainline quality standard (2% CO_2) used by the State in computing royalties does not agree with the mainline quality standards identified in the record for portions of the audit period (1-3% CO_2).[10] Therefore, the

---

[9] As stated above, less than 10 percent of the coalbed methane is sold and utilized with a CO_2 content exceeding the mainline quality requirement at the wellhead. More than 90 percent of the production is treated to comply with the mainline quality specifications before being sold into market(s) outside the field and area. Thus, the "typical" sale of field and area coalbed methane occurs at the mainline CO_2 quality.

[10] The evidence in the record indicates that the mainline transporters' (El Paso Natural Gas, Transwestern, and Northwest Pipeline) CO_2 quality requirements vary from one to three percent (1-3%) content of coalbed methane volume over the audit period.

Order is modified and the Appellant must recalculate the royalties due for the audited leases during the audit period based on the content acceptable to the pipeline purchasers. The lessor will not share in treatment costs simply because one purchaser may require a marginally lower CO_2 content than another. Nor will the lessor require the lessee to condition the gas to a higher level of purity than the pipeline purchaser requires.

To summarize, the costs of CO_2 removal are the responsibility of the lessee when gas must be conditioned to meet the quality requirements typical for sales of gas from the field or area. Where there is no market for the gas at issue in the field or area, the marketable condition requirement is the quality of the mainline transportation to the downstream market. Thus, this portion of the appeal is denied and the Order is modified as explained above. The actual mainline quality specifications shall be used in all instances, including any quality specifications that were "grandfathered."

The above determination affects the coalbed methane subject to the RVD Decision as well as the Order. Where the costs of gas treatment are necessary to place production in marketable condition, those same costs cannot also be considered allowable as a cost to either transport or process the gas since gas conditioning must be performed cost-free to the lessor. 30 CFR 205.152(1) and 206.158(d)(1) (1989).

b. Extraordinary Processing Cost

As an alternative theory to including the cost of CO_2 removal as a cost of transportation (*see infra* section 2), ARCO/Vastar argues that it is entitled to an extraordinary processing cost allowance for removing CO_2 from the

---

SSOR at Exhibit No. 5. Further, El Paso Natural Gas "grandfathered" the CO_2 allowed for mainline transportation from the Val Verde Plant at 2.13 percent. *Id.* (*See* Tariff No. 221 dated July 7, 1994).

coalbed gas stream regardless of whether the CO_2 was marketed and sold. Response to RVD Decision FR at 2. ARCO/Vastar points to MMS's approval of Louisiana Land and Exploration Company's (LL&E) extraordinary processing cost request to remove impurities (including CO_2) from its Lost Cabin Plant in Wyoming. Similar to CO_2 removed at the Val Verde Plant, the CO_2 removed at the Lost Cabin Plant was not marketed or sold.[11] Therefore, ARCO/Vastar argues that MMS's failure to grant it similar consideration regarding an extraordinary processing cost allowance for removing CO_2 that was not marketed and sold would result in an arbitrary and capricious application of the regulations. *Id.* at 2-3.

ARCO/Vastar also argues that MMS's March 19, 1996, Guidance for Extraordinary Processing Cost Allowance Applications (Guidelines)[12] clearly contemplate granting an extraordinary processing cost allowance when gas plant products are not sold.[13] *Id.* at 3. Lastly, ARCO/Vastar argues that methane is a product against which the extraordinary processing cost allowances may be deducted. *Id.* at 3-4.

The MMS argues that an allowance for processing may not be claimed for removal of the CO_2 because the CO_2 is not marketed and sold. (Instead, it is simply vented into the atmosphere.) Order at 3; RVD Decision at 5. The MMS

---

[11] *See* Response to RVD Decision FR. Exhibit 4 at 1.

[12] Apparently, these same guidelines were issued by RVD (formerly Valuation and Standards Division at the time of issuance) on February 6, 1996. Whether this was an internal issue date versus the March issue date to the public is not clear from the record. Regardless, both documents will be treated as identical herein and will be referenced as the "Guidelines."

[13] *See* Response to RVD Decision FR, Exhibit 3 at 4.

will not grant an allowance for the cost of processing when the lease production is not royalty bearing.[14] *Id.*

The gas processing regulations provide:

> *Except as provided in paragraph (d)(2) of this section, no processing cost deduction shall be allowed for the costs of placing lease products in marketable condition*, including dehydration, separation, compression, or storage, even if those functions are performed off the lease or at a processing plant. Where gas is processed for the removal of acid gases, commonly referred to as "sweetening," no processing cost deduction shall be allowed for such costs unless the acid gases removed are further processed into a gas plant product. In such event, the lessee shall be eligible for a processing allowance as determined in accordance with this subpart. *However, MMS will not grant any processing allowance for processing lease production which is not royalty bearing.*

30 CFR 206.158(d)(1) (1989) (emphasis added).

Although the concept of marketable condition described above includes the processes of dehydration, separation, compression, and storage, the list is illustrative and is not all-inclusive. Placing production into marketable condition includes any process used to treat or condition gas (remove impurities) necessary to meet contract quality specifications. 30 CFR 206.151. Thus, the processing of gas for the purpose of removing impurities falls within the concept of placing production in marketable condition.

As determined in section 1.a, above, the removal of CO_2 is required to place the production in marketable condition. The CO_2 is not captured and sold and is not a royalty-

---

[14] The RVD Decision implies that an extraordinary cost processing allowance will not be granted in the absence of a processing allowance for that same gas plant product. *See* Decision at 5.

bearing product. Under the facts of this case, CO_2 is an impurity. In accordance with the gas processing regulations, "no processing cost deduction shall be allowed for the costs of placing lease products in marketable condition." 30 CFR 206.158(d)(1). However, processing circumstances qualifying under subsection 30 CFR 206.158 (d)(2) may result in an exception to the marketable condition requirement of subsection (d)(1). Thus, the question arises whether the requirement that the lease production be royalty-bearing precludes granting of an extraordinary processing cost allowance for removing CO_2 as well as a processing allowance.

For purposes of this decision, however, it is not necessary to resolve that issue because ARCO/Vastar fails to meet the requirements of paragraph (d)(2) in any event. Section 206.158(d)(2)(i) provides:

> If the lessee incurs extraordinary costs for processing gas production from a gas production operation, it may apply to MMS for an allowance for those costs which shall be in addition to any other processing allowance to which the lessee is entitled pu[r]suant to this section. Such an allowance may be granted only if the lessee can demonstrate that the costs are, by reference to standard industry conditions and practice, extraordinary, unusual, or unconventional.

ARCO/Vastar argues that the amine process[15] used in the Val Verde Plant to extract the CO_2 *meets the criteria of paragraph (d)(2) to qualify as an extraordinary processing allowance for the costs of CO_2 removal* [emphasis added] because: 1) the gas stream is atypical, 2) the process used to remove CO_2 is unique, and 3) the costs of CO_2 removal are extraordinary. Response to RVD Decision FR at 2-7; SOR to RVD Decision at 2-4. ARCO/Vastar believes that

---

[15] The amine process in the Val Verde Plant utilizes diethanolamine or DEA.

coalbed methane treatment at the Val Verde Plant is similar to processing of production entering Exxon Corporation's LaBarge facility, and that IBLA's Decision in *Exxon Corp.*, 118 IBLA 221 (1991), should control. SSOR at 16-18.

The RVD determined that ARCO/Vastar's costs of extracting CO_2 from the coalbed methane at the Val Verde Plant do not qualify as an extraordinary processing allowance. The RVD argues that: 1) the uniqueness of the gas stream is debatable, 2) the amine process is not unconventional, and 3) the costs of extracting CO_2 do not appear to be extraordinary. RVD Decision at 6.

The MMS's March 1996 Guidelines were issued to provide further explanation of the criteria relevant to determining whether particular gas meets paragraph (d)(2)'s requirements. The criteria focus on gas composition, plant processes, and cost of plant processes relative to what is considered those same factors for "standard" gas processing plants. Guidelines at 2. (The criterion of "atypical" gas arose in the MMS's *Oil and Gas Payor Handbook, Volume III* (*Payor Handbook*), released July 21, 1993, but no additional guidance on the other criteria was provided in that release.) In addition, MMS issued a "Dear Operator/Payor Letter" on April 22, 1996, that specifically addressed coalbed methane valuation and reporting, but these guidelines do not address the applicability of extraordinary processing cost allowances.[16]

---

[16] The Guidelines in the April 1996 Dear Operator/Payor Letter did not fully convey MMS's Royalty Policy Board's (Board) findings regarding processing allowances applicable to CO_2. The Board addressed the issue of extraordinary processing cost allowances for coalbed methane by concluding that where CO_2 is vented and not sold, the cost of the CO_2 extraction process is not warranted. *See* MMS Royalty Policy Board Guidelines (December 7, 1995) at 2-3.

ARCO/Vastar argues that the coalbed methane stream is "atypical" due to its composition, and unlike a conventional gas stream, the coalbed gas' composition changes over time. SSOR at 17. ARCO/Vastar's coalbed gas compositional analyses from three Central Delivery Points (CDP's) serving the audited leases reveals between 83.87 to 87.08 percent methane, 12.65 to 15.86 percent CO_2, 0.23 to 0.35 percent ethane, and trace amounts of nitrogen. Response to RVD Decision FR at Exhibit 5.

The RVD argues that "no liquid hydrocarbons does not make [ARCO/Vastar's coalbed gas] unusual," that the CO_2 content "is not a compelling argument for classifying the gas as unusual or atypical," and that the large volume of this particular composition "makes it difficult to classify this gas as unusual or atypical." RVD Decision at 4. The RVD concludes that "[t]he pertinent factor ... is whether the chemical composition of the gas stream required processing of an extraordinary, unusual or unconventional nature." *Id.* In the RVD Decision Field Report, RVD argues that the definition of atypical in the *Payor Handbook* is not formal and that the "*regulations provide that cost, not composition, is the determining factor in granting an extraordinary processing cost allowance.*" RVD Decision FR at 6 (emphasis in original).

The sole source where MMS defines "atypical" is in its *Payor Handbook.*[17] This definition was derived from the first Departmental approval of an extraordinary processing cost allowance.[18] The term appears to describe the nature of the gas stream in the *LL&E* and *Exxon* decisions by

---

[17] "Atypical" gas is defined as gas that does not contain liquefiable hydrocarbons, such as ethane, propane, butane, etc." *Payor Handbook* at 7.1.2.

[18] *See* August 13, 1992, Assistant Secretary for Land and Minerals Decision in *Exxon Corporation* (citing the atypical nature of the gas stream with no liquefiable hydrocarbons).

alluding to the absence of liquefiable hydrocarbons in the respective gas streams. However, the more important aspect of designating a gas stream as atypical is where the *Payor Handbook* requires the determination in order to further consider the other aspects of approving an extraordinary processing cost allowance.[19] *See Payor Handbook* at 7.1.2. Thus, the degree to which a particular gas stream is atypical is not as important as the atypical designation itself as a threshold determination in approving an extraordinary processing cost allowance.

Because the *Payor Handbook* is the sole source of defining atypical and because of the threshold emphasis the *Payor Handbook* places on the atypical designation, ARCO/Vastar's gas stream at issue here qualifies as atypical. However, this determination is not dispositive of the extraordinary processing cost allowance issue, but simply begins the analysis.

ARCO/Vastar argues that the Val Verde Plant process is unconventional and complex because the amine process used to remove CO_2 is chemical versus the physical extraction processes used to typically extract natural gas liquids. Also, ARCO/Vastar argues that the amine process is distinguishable from other plants that use amine because the Val Verde Plant uses a greater percentage of amine, which requires much more water, and the plant requires stainless steel in certain areas versus carbon steel used in other amine plants. SSOR at 17. The technical features of the Val Verde Plant alluded to above are described in two engineering papers[20] contained in the record. Response to

---

[19] The Guidelines are silent concerning the atypical nature of the gas stream. Instead, the Guidelines focus on whether the gas stream composition either is unusual compared to conventional gas streams or is similar to previously determined unconventional gas streams.

[20] *See, e.g.*, Anderson, *Comparison of Val Verde Plant to LaBarge Plant.* SOR at Exhibit 10: Anderson, *The Treatment of Coal Seams*

RVD Decision FR at 6. Lastly, ARCO/Vastar argues that a gas processing plant does not have to be "one-of-a-kind" in order to be eligible for an extraordinary processing cost allowance. *Id.*

The RVD argues that the amine process used in the Val Verde Plant for CO_2 removal is neither unconventional nor extraordinary. The RVD also argues that the Val Verde Plant design and equipment utilizing the amine process is "much the same for both coalbed and non-coalbed gas plants." RVD Decision at 5: RVD Decision FR at 8-9.

ARCO/Vastar argues that the amine process is complex and unusual by focusing on the type, concentration, and amount of amine (requiring use of 316L stainless steel), and the amount of water required. The use of amine processes in gas processing plants is quite common. ARCO/Vastar's arguments that its amine process is unusual primarily address the plant's larger size and throughput volumes. Compared to a conventional gas processing plant, the Val Verde Plant lacks any of the equipment necessary to extract natural gas liquids or to recover sulfur. Thus, the Val Verde Plant is composed of only one part of what is considered a fairly complex natural gas processing plant.[21] Given the lack of plant complexity and the common nature of the amine process, the Val Verde Plant is neither unconventional nor extraordinary.

ARCO/Vastar argues that the $0.0778 per Mcf cost to recover methane is significant. SSOR at 17: Response to RVD Decision FR at 7.

Gas at Val Verde Plant (1992). Response to RVD Decision FR at Exhibit 6.

[21] The MMS considers Exxon's LeBarge Plant and LL&E's Lost Cabin Plant to represent complex gas processing plants. The cost to process methane in these plants is substantially greater than the costs claimed by ARCO/Vastar to be significant.

The RVD claims that ARCO/Vastar's cost is at the low end of the range of CO_2 removal. RVD Decision FR at 10.

The issue in determining the qualification of processing costs as an extraordinary allowance is the extent of the costs incurred by reference to standard industry costs. 30 CFR 206.158(d)(2)(1). Here, ARCO/Vastar simply refers to the costs as significant, but the record contains no documentation demonstrating that the costs represent an extraordinary rather than a typical expense for the treatment performed. Therefore, in the absence of substantiating the extraordinary nature of processing costs with reference to standard industry costs, ARCO/Vastar's application for an extraordinary processing cost allowance must be denied in any event.

The conclusion above regarding the non-qualification of CO_2 removal costs as an extraordinary gas processing cost allowance applies to both the Order and the RVD Decision. The Order and RVD Decision are modified to the extent necessary to conform to the decision above.

2. *Analysis - Transportation*

The MMS states in the Order that "[t]ransportation allowances are granted for the reasonable, actual necessary costs of transporting the coalbed methane from the royalty measurement point (either the well or the Central Delivery Point (CDP) [)] to the point of sale remote from the lease." Order at 2. Further, "no allowance may be taken for the costs of transporting lease production which is not royalty bearing without MMS approval." 30 CFR 206.157(a)(2)(i) (1989).

The transporters at or near the tailgate of the Val Verde Plant (e.g., El Paso Natural Gas Company, Transwestern Pipeline Company, and Northwestern Pipeline Company) currently specify in their transportation agreements that the gas quality cannot exceed two percent of CO_2 for

mainline transport."[22] In addition, the guidance provided by MMS states that "transportation costs [can only be] allocated to the methane component for the amount of CO_2 permitted in the main (inter- or intrastate) transmission line." April 22, 1996, Dear Operator/Payor Letter at 2. Consequently, the State disallowed costs to transport CO_2 exceeding two percent of the combined volume of gas.

The Appellant argues that the State is restricting the allocation of transportation costs to gas that is at the interstate pipeline standard of two percent CO_2 and that the State considers CO_2 in excess of that standard a non-royalty bearing product. However, the Appellant contends that the cost of transporting CO_2 should be included as part of the transportation allowance for methane because unmarketable CO_2 is a waste product to which no allocation of transportation costs should apply in accordance with 30 CFR 206.157(a)(2)(1) (1989). SSOR at 14.

Further, ARCO/Vastar states that the primary reason for removing the CO_2 is to transport the gas stream, not to place it in marketable condition. ARCO/Vastar concludes that CO_2 removal should be treated the same as the dehydration costs in *Exxon*, 118 IBLA at 221, and the liquefaction costs in *Marathon Oil Co. v. United States*, 604 F. Supp. 1375 (D. Alaska 1985), *aff'd* 807 F.2d 759 (9th Cir. 1986), *cert. denied*, 480 U.S. 940 (1987). SSOR at 16. I disagree with the Appellant's contentions.

a. *January 1989 - March 1992*

For the period January 1989 through March 1992, all of ARCO/Vastar's gas was sold at the wellhead, but it was not in marketable condition, as determined in section 1 above. The "Gas Gathering and Treating Agreement" between MOGI and ARCO Oil and Gas Company dated December 17, 1990, applicable to the audited leases specifies a fee of

---

[22] *See supra* note 10.

$0.36 per Mcf for treatment and transportation. Because the treatment fee is $0.0778 per Mcf, the remainder of the fee is for transportation.

The State argues that since approximately $0.2822 per Mcf is charged for transporting the entire coalbed methane stream, the portion of the fee applicable to the CO_2 content in excess of the mainline allowable cannot reduce the value of the production used to calculate the royalty. The payment received for sales under the Unit Operating Agreement at the wellhead reflected a reduction of the sales price for the cost of treating and transporting the coalbed methane and the CO_2.[23] Since the Appellant's sales price at the wellhead or CDP during the period January 1989 through March 1992 included a reduction for not only the transportation of the methane and the 2% CO_2 allowed of mainline transport but also a reduction for transportation of the remainder of the CO_2 to the Val Verde Plant, the value used to calculate the royalty must include not only the sales price of the coalbed gas stream, but also the amount of non-allowable reduction of the sale price for transportation of the CO_2 in excess of the 2%.

The costs of transporting the CO_2 component above the mainline standards, which are costs of transporting a non-royalty-bearing product as addressed in section 2.c. below, must be added to the lessee's wellhead gross proceeds. This is in keeping with the principle that the Department cannot allow producers to simply alter the form of their sales arrangements in order to force the lessor to share in

---

[23] The Appellant stipulates that its wellhead sales were to Meridian Oil Inc. SSOR at 10. MOGI provides the services under the "Gas Gathering and Treatment Agreement" to the Appellant. Because of the inter-relationships between the coalbed methane sales and its treatment, the State claims that "third party" information verifies that the Meridian affiliates incorporated (deducted) the cost of treatment and transportation into the production's market value at the Val Verde Plant.

costs in which it does not otherwise share. Also, the transportation of the CO_2 to the treatment plant in this instance is a service that is inextricably tied to placing the gas in marketable condition because the CO_2 is extracted at the plant. Thus, the lessee's gross proceeds must be increased to the extent they have been reduced because the purchaser was providing these services to place the production in marketable condition. *See* 30 CFR 206.152(i). Thus, this portion of the appeal is denied.

b. *Post March 1992*

For all gas that is sold downstream of the wellhead or CDP, a transportation allowance may be applicable. "Since March 1992, ARCO has marketed their production under various selling arrangements." Order at 5. However, evidence of the "various selling arrangements" is not contained in the record. For these sales of gas, the regulations at 30 CFR 206.156 and 206.157 (1989) govern applicable transportation allowances subject to the determination in part 2.c. below.

c. *Transportation of Waste*

ARCO/Vastar argues that the State incorrectly computes the allowable costs of CO_2 transportation both from the wellhead/CDP to the plant and from the plant to the point of sale. ARCO/Vastar contends that allocation to the methane stream of the costs of transporting a CO_2 waste product comports with the valuation regulations and that there is no reason for treating amounts of "waste" CO_2 within interstate pipeline standards, i.e., less than two percent, differently than amounts in excess of those standards. SSOR at 13-15. I disagree.

The issue of transporting CO_2 in excess of the mainline quality standard downstream of the Val Verde Plant has already been addressed, in effect, by the marketable condition determination in section 1 above. In other words, because the coalbed methane must be placed in a marketable

condition prior to mainline transportation, there are no CO_2 volumes that must otherwise be transported downstream of the plant. Thus, the sole issue regarding CO_2 waste volumes pertains to the transportation of the coalbed methane from the wellhead to the Val Verde Plant for the remainder of the audit period commencing May 1992.

The guidance provided by the *Payor Handbook* notes that "[t]ransportation costs for a gaseous stream [or a liquid and gaseous stream] are allocated only to the royalty-bearing and non-royalty-bearing products. For transportation cost allocation purposes, a waste product is considered neither royalty-bearing nor non-royalty-bearing. Therefore, the waste product volume is excluded from the cost allocation." *Payor Handbook* 6.4.1.

The three examples contained in section 6.4 of the *Payor Handbook* all assume that CO_2 is a waste product. Additional guidance is contained in the April 22, 1996, Dear Operator/Payor Letter. In assessing additional royalties on ARCO/Vastar for transportation of CO_2 volumes, MMS followed the guidance in the Dear Operator/Payor Letter, which states:

> For coalbed methane production, you can increase the transportation costs allocated to the methane component for the amount of CO_2 permitted in the main (inter- or intrastate) transmission line. For example, if your gas stream consists of 90 percent methane and 10 percent CO_2 and the main transmission line allows 2 percent CO_2 in the makeup of its gas stream, you can include the costs of transporting the 2 percent CO_2 volume (or 92 percent of the total transportation cost) when calculating your allowance for methane.

Dear Operator/Payor Letter at 2.[24]

The valuation regulations address waste as follows:

> [T]he total transportation costs shall be allocated in a consistent and equitable manner to each of the products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, no allowance may be taken for costs of transporting lease production which is not royalty bearing.

30 CFR 206.157(a)(2)(i); 206.157(b)(3)(i).

The preamble to the revised valuation regulations published in the *Federal Register* on January 15, 1988, provides:

> The MMS does not agree with the commenters' proposal that the cost of transporting nonroyalty-bearing substances should be shared by the lessor in all instances. However, upon review, MMS has recognized that it is appropriate to provide an allowance which includes the costs of transporting certain nonroyalty-bearing substances such as waste products, including water. For example, there may be circumstances where transportation of water along with the royalty-bearing portion of the production is necessary. For other than waste products, the final rule provides, however, that prior MMS approval is required before an allowance may be taken for the costs of transporting non-royalty-bearing substances.

53 F.R. 1230, 1258 (1988).

---

[24] A Dear Payor Letter issued February 4, 1988, also addresses transportation cost allocation among produced products, but it does not contain the CO_2 instructions issued in the April 22, 1996, Dear Operator/Payor Letter. *See supra* note 6.

The regulations do not specifically explain the distinction between "non-royalty-bearing products" and "waste products." The guidance provided in the Dear Operator/Payor Letter treats CO_2 as a non-royalty-bearing product, but then directs the operator/payor to "use the regulation in 30 CFR 206.156 and 206.157 (1995) and the instructions in Chapter 6 of the *Oil and Gas Payor Handbook, Volume III*, to calculate your transportation allowance."

Arguably, one could infer from the *Payor Handbook* hypotheticals that CO_2 in this situation is assumed to be a "waste product." To do so, however, would be incorrect.[25]

The intent of the *Payor Handbook* examples is apparent. Proportionate measures of the identified gas stream constituents affect the computation of transportation allowances. Had the numbers given in the examples represented volumes instead of Btu's, the results would have been what MMS intended. The reference to CO_2 as a waste product would also have made sense with respect to the regulations.

The MMS allocates the cost of transporting the mainline allowable non-methane constituents in a gas stream to the methane component. This is the only portion of the non-royalty-bearing production that is considered a waste product. Even in the *Payor Handbook* examples, the fraction of CO_2 in the examples represented typical mainline allowables; representing from one to two-and-one-half percent (1-2½%) of the heating value (sic) of the gas stream.

The Dear/Operator/Payor Letter guidance primarily treats the CO_2 content that was removed from the coalbed

---

[25] The *Payor Handbook* examples at 6.4.1, 6.4.2, and 6.4.3 contain unfortunate ambiguities. They refer to gas streams that have MMBtu measures of CO_2 and helium. Neither CO_2 nor helium have energy contents (Btu's). Thus, the hypothetical examples are difficult to apply because we have no idea of the volumes of these gas stream constituents upon which to compute transportation allowances.

methane as a non-royalty-bearing product. Only the pipeline allowable CO_2 content (remaining in the methane stream) is treated as a waste product.[26] The fact that a small amount of waste product remains is primarily the result of inefficiencies involved in further removal. Beyond a point, inefficiencies of removal processes and/or pipeline tolerances[27] dictate against further removal of impurities, which then become a waste product (as opposed to its non-royalty bearing status if present in amounts greater than the quality specifications of the mainline).

The valuation regulations specify that transportation costs are to be allocated to all royalty-bearing products after excluding waste products, both from the total volume and from the volume of all products. 30 CFR 206.157(a)(2)(i); 206.157(b)(3)(i). In addition, the preamble providing the rationale for these regulations clearly indicates that the cost to transport non-royalty-bearing products that are not waste products will not be included in the allowable transportation deduction for royalty-bearing products. 53 F.R. 1230, 1258 (1988). The preamble implication that MMS will approve an allowance for the costs to transport non-royalty-bearing substances is limited to those non-royalty-bearing substances that are also waste products as defined above. *Id.*

Here, the CO_2 produced in conjunction with the methane from the coalbed is transported to a treatment plant, separated (save for two percent content) from the methane, and vented. There is no market for this CO_2. The intent of MMS's regulations and *Payor Handbook* is that waste

---

[26] The cost to transport the interstate pipeline allowable CO_2 content is allocated to the methane and allowed as a cost of transporting the methane. *See* Dear Operator/Payor Letter at 2.

[27] Pipeline tolerances used in this context refers to the physical ability of the pipeline to operate efficiently at certain levels of non-methane constituents or contaminants.

production for the purpose of determining allowable transportation costs is the fraction of non-royalty-bearing product that is allowable in a mainline transportation system. In the instant case, all CO_2 in excess of the mainline standard is non-royalty-bearing production. Therefore, this portion of the appeal is denied.

Consistent with the modification in section 1 above, the mainline standard of allowable CO_2 (2% CO_2) used by the State in computing royalties does not agree with the mainline quality standards identified in the record for portions of the adult period (1-3% CO_2).[28] Therefore, the Order is modified and the Appellant must recalculate the royalties due for the audited leases during the audit period based on the guidance above.

3. *Analysis - Administrative Procedure Act*

ARCO/Vastar avers that the State is applying the April 22, 1996, Dear Operator/Payor Letter as a rule in violation of the Administrative Procedure Act (APA). 5 U.S.C. 551-559, 701-706 (1994). In support of its position, the Appellant cites *Phillips Petroleum Co. v. Johnson*, 22 F.3d 616 (5th Cir. 1994), *cert. denied*, 514 U.S. 1092 (1995). Under *Phillips*, the court determined that the APA required notice and comment rulemaking for the valuation procedures at issue in that case. In addition, ARCO/Vastar argue that the supposedly newly-instituted procedures cannot be applied retroactively. SSOR at 18-21.

Here, the State applied the existing valuation regulations which were further explained by the April 22, 1996, Dear Operator/Payor Letter. To the extent that the State's interpretation was inconsistent with the regulations, this decision modifies the Order to make it consistent with the regulations.

---

[28] *See supra* note 10.

When, through notices or interpretive rules, the Government explains and clarifies existing regulations, the procedural requirements of rulemaking under the Administrative Procedure Act, 5 U.S.C. 553 (1982), are not applicable. *Venlease I*, 99 IBLA 387 (1987). *See Shalala v. Guernsey Memorial Hospital*, 514 U.S. 87, 115 S. Ct. 1232 (1995). The Dear Operator/Payor Letter is an interpretation of existing regulations. Therefore, this portion of the appeal is denied.

4. *Analysis - Late Payment Interest*

The Appellant argues that it would be inequitable to assess late payment interest on royalties due based on a valuation procedure that could not have been anticipated by lessees. SSOR at 21.

Assessments of late payment charges are supported by longstanding precedent. *See Gary-Williams Energy Corporation*, MMS-91-0366-IND (May 15, 1992). 13 Gower Federal Service, Royalty Valuation and Management, Rocky Mountain Mineral Law Foundation, and cases therein cited. In *Gary-Williams*, the Appellant's challenge to the late payment assessment was limited to the application of a new valuation procedure. Inasmuch as the valuation procedure was determined to be interpretative of existing regulations, the assessment was proper. *See Columbia Gas Development Corp.*, 123 IBLA 395 (August 7, 1992) (holding that the late payment assessments were appropriate since the underpaid lease remained in an underpaid status for several months until a corrected Form MMS-2014 was filed).

The same reasoning applies in this appeal since the valuation procedure was, like in *Gary-Williams*, an interpretation of existing regulations. Accordingly, the late payment assessment must be sustained.

Conclusion

1. Was the cost of CO_2 removal a.) necessary to place the gas in marketable condition, or b.) allowable as an extraordinary processing cost allowance? The gas was not in marketable condition for its object market. The cost to place the production into marketable condition is to be borne by the lessee at no cost to the lessor. Thus, the arm's-length proceeds received for the wellhead sale of gas must be adjusted for the cost of placing the gas in marketable condition. The removal of CO_2 from the coalbed gas stream is required to place the gas in marketable condition. Costs to place gas in marketable condition do not qualify as costs of processing.

Further, the cost to remove CO_2 from the gas stream does not qualify as an extraordinary gas processing allowance because the Val Verde Plant process and costs incurred to remove CO_2 do not qualify as extraordinary, unusual, or unconventional by reference to standard industry costs for similar CO_2 removal processes.

2. Are costs incurred to transport coalbed methane deductible?

When gas is sold at the wellhead, transportation costs are not allowed to be deducted from the value of production for royalty purposes. Costs to transport non-royalty-bearing production to enable the production to be placed in a marketable condition are not allowed, except to the extent that the mainline transporter allows a specified amount.

When the lessee transports gas from the lease to a point of sale away from the lease, the cost to transport the gas may be allowable. The cost to transport gas is not allocable to waste products, but is allocable to royalty-bearing and non-royalty-bearing, non-waste production. The portion of the cost allocated to non-royalty-bearing product is not deductible as an allowance. Waste is defined as the mainline

allowable portion of a particular non-methane constituent of the gas.

3. Does the April 22, 1996, Dear Operator/Payor Letter violate the Administrative Procedure Act?

The Dear Operator/Payor Letter is an interpretive guide to existing regulations. Thus, the procedure contained in the Dear Operator/Payor Letter does not violate the Administrative Procedure Act.

4. Is late payment interest applicable to royalties deemed deficient for prior periods?

The lessee cannot avoid late payment interest assessed on unpaid royalty for prior periods.

ARCO/Vastar must recalculate the royalties due accordingly.

Because this decision is issued by an Assistant Secretary of the Department of the Interior, it is not subject to appeal to the Interior Board of Land Appeals and is the final action of the Department. *Blue Star Inc.*, 41 IBLA 333 (1979); *Marathon Oil Co.*, 108 IBLA 177 (1989).

Sincerely

/s/ Sylvia V. Baca
Sylvia V. Baca
Assistant Secretary, Land
and Minerals Management

APPENDIX G

[Seal Omitted]

United States Department of the Interior

MINERALS MANAGEMENT SERVICE

Royalty Management Program
P.O. Box 25165
Denver, Colorado 80225-0165

MMS/RVD-OG: 97-0315
Mail Stop 3152 February 26, 1998

Memorandum

To: Chief, Appeals Division
Policy and Management Improvement

From: Chief, Royalty Valuation Division
/s/ Deborah Gibb Tschudy

Subject: Field Report on Appeal by Vastar Resources, Inc. (Vastar) Regarding Denial of Extraordinary Processing Cost Allowance, Appeal Docket No. MMS-97-0191-O&G

By letter dated August 14, 1997 (Attachment 1), Vastar appealed Royalty Valuation Division's (RVD) decision of July 14, 1997 (Attachment 2), denying Vastar's application for an extraordinary processing cost allowance (Attachment 3). The appeal was timely filed and assigned Docket No. MMS-97-0191-O&G (Attachment 4). RVD granted Vastar extensions to file its Statement of Reasons (SOR) until October 16 and November 12, 1997 (Attachment 5). The extensions prolong for 87 days the 33-month time frame for processing appeals as set out in 30 U.S.C. 1725(h)(l) and any time frame Minerals Management Service (MMS) may provide for by regulation. Vastar submitted to SOR (Attachment 6) on November 12, 1997.

Vastar has requested the subject appeal be consolidated with appeal Docket No. MMS-97-0063-O&G (Attachment 7).

Because RVD is not a party to that appeal, we address only the issue of an extraordinary processing cost allowance to appeal here. However, to the extent the two appeals overlap with respect to extraordinary processing cost allowances, this report will also apply to appeal Docket No. MMS-97-0063-O&G.

ISSUE

At issue is whether Vastar's coalbed gas (also called coalbed methane) is eligible for an extraordinary processing cost allowance.

RECOMMENDATION

We recommend the appeal be denied on the grounds that Vastar's coalbed gas does not qualify for an extraordinary processing cost allowance.

BACKGROUND

Vastar produces coalbed gas from leases in the San Juan Basin, New Mexico. The gas contains carbon dioxide (CO_2) in excess of that allowed by the major pipelines servicing the area.[1] The gas is gathered by Burlington Resources Inc. (Burlington) and treated at Burlington's Val Verde Gas Plant to remove the excess CO_2.

The Val Verde Plant employs the amine process to remove CO_2 from the gas stream. The extracted CO_2 is vented to the atmosphere. Burlington does not charge an individual

---

[1] El Paso Natural Gas Company permits a maximum 2.13 percent CO_2 for gas entering its pipeline from the Val Verde Plant. Other major gas transportation companies servicing the San Juan Basin generally permit a maximum 2 percent CO_2 in their pipelines. Although Vastar does not give its coalbed gas composition, its leases are located in the "overpressured, high CO_2 area" of the San Juan Basin. Coalbed gas from this area typically consists of 85 to 100 percent methane, less than 1 percent to more than 13 percent CO_2, and negligible amounts of liquid hydrocarbons (natural gas liquids) and nitrogen. Gas entering the Val Verde Gas Plant averages about 11.3 percent CO_2.

fee for the CO_2-removal service.[2] Rather, the cost of removing the CO_2 is part of a bundled services fee that Burlington charges for both gathering the coalbed gas from the production field and treating the gas (removing the CO_2) at the Val Verde Plant. In response to MMS's policy on coalbed gas valuation, Burlington attributes $0.0778/Mcf of the bundled services fee to CO_2 removal.

Vastar seeks an extraordinary processing cost allowance pursuant to 30 CFR § 206.158(d)(2) (1997) to deduct from royalty value the costs charged by Burlington for extracting the CO_2. In its allowance application (Attachment 3), Vastar contended that the composition of the gas stream, plant design, and costs are sufficiently extraordinary to warrant such an allowance. RVD determined in its July 14, 1997, decision that the gas does not qualify for an e. ordinary processing cost allowance. Attachment 2 gives the rationale for our decision and is incorporated herein by reference as support of this field report. Vastar's arguments in its SORs remain much the same as in its allowance application.

Vastar continues to assert that an extraordinary processing cost allowance is proper because it meets the criteria set forth in MMS's processing cost allowance guidelines (Attachment 8) and the requirements in 30 CFR § 206.158(d)(2). Specifically, Vastar contends:

1. The composition of the gas stream is atypical when compared to conventional gas (SOR for MMS-97-0191-O&G at p. 2). (Vastar originally argued the gas was "unique.")

---

[2] Vastar did not submit its gathering and treating agreement with Burlington. However, it is common knowledge that Burlington and other companies that gather and treat coalbed gas in the San Juan Basin charge bundled services fees.

2. The CO_2-removal process is more than conventionally used to process gas (SOR for MMS-97-0063-O&G at p. 17).
3. The unit cost to recover the principal product, methane, is significant (SOR for MMS-97-0063-O&G at p. 17).

Vastar also argues:

4. The composition of the gas stream and processing techniques is in several respects comparable to the circumstances in *Exxon Corp.*, 118 IBLA 221 (1991), in which the Interior Board of Land Appeals (IBLA) found that an extraordinary processing cost allowance was proper (SOR for MMS-97-0191-O&G at p. 2).
5. RVD's application denial is so consistent with MMS's prior interpretations of the regulations and guidelines as to be arbitrary and capricious (SOR for MMS-97-0191-O&G at p. 2).

Arguments 1 through 3 form the factual core of Vastar's appeal. Although RVD addressed these arguments in its denial decision (Attachment 2), we further elaborate on them here. Arguments 4 and 5 are ancillary to the main issue; we only comment on these arguments for informational purposes.

APPLICABLE REGULATIONS AND GUIDELINES

Regulations

Pertinent rules governing processing allowances are found in 30 CFR § 206.158 (1997) as follows:

- First, 30 CFR § 206.158(a) (1997) permits the lessee to claim a deduction (a "processing allowance") for its reasonable, actual costs of processing when gas is processed. Regulations at 30 CFR § 206.151 (1997) define "processing" as any process, including absorption, or refrigeration, designed to remove elements or

compounds (hydrocarbon or nonhydrocarbon) from the natural gas stream.

- Second, 30 CFR § 206.158(b) (1997) directs that processing costs must be allocated among the gas plant products. Regulations at 30 CFR § 206.151 define "gas plant products" as separate marketable elements, compounds, or mixtures resulting from processing gas, excluding residue gas (methane). (Carbon dioxide can qualify as a gas plant product.)
- Third, 30 CFR § 206.158(c)(1) (1997) provides that a processing allowance cannot be applied against the value of the residue gas, unless MMS grants an extraordinary processing cost allowance.
- Fourth, 30 CFR § 206.158(c)(2) (1997) limits the processing allowances to 66 2/3 percent of the transportation-adjusted value of each gas plant product. MMS may approve a greater allowance under the companion rule at 30 CFR § 206.158(c)(3) (1997), but the greater processing allowance cannot reduce the value of any gas plant product to zero. (In applying this rule, MMS will grant a processing allowance up to 99 percent of the value of a gas plant product.)
- Fifth, 30 CFR § 206.158(d)(1) (1997) provides that no processing cost deduction shall be allowed for the costs of placing lease products in marketable condition, unless otherwise approved through an extraordinary cost allowance. This regulation further states that no deductions shall be allowed for the costs of removing acid gases, commonly referred to as "sweetening," unless the acid gases removed are further processed into gas plant products (meaning marketable products under the definition at 30 CFR § 206.151). (Carbon dioxide is an acid gas.) This regulation also provides that MMS will not grant any pro-

cessing allowance for processing lease production that is not royalty bearing.

- Finally, 30 CFR § 206.158(d)(2)(i) (1997) permits a lessee to apply for an extraordinary processing cost allowance, if such costs are incurred. However, the lessee must demonstrate that the costs are extraordinary, unusual, or unconventional by reference to standard industry conditions and practice. This regulation states that the extraordinary processing cost allowance shall be in addition to any other processing allowance to which the lessee is entitled.

Extraordinary Processing Cost Allowance Guidelines

MMS issued guidelines for preparing and reviewing extraordinary processing cost allowance applications on March 19, 1996 (Attachment 8). Under these guidelines, MMS considers one or more of the following factors to determine whether an extraordinary processing cost allowance is appropriate:

- The composition of the gas stream being processed.
- The complexity of the gas plant design compared to conventional or typical gas processing plants, as well as methods (absorption, adsorption, refrigeration, cryogenic, etc.) used to process the gas to remove elements or compounds (hydrocarbon or nonhydrocarbon) from the gas.
- The unit costs incurred to recover the principal product, usually methane.

MMS evaluates these factors to determine if they are clearly extraordinary in relation to other gas plants.

Coalbed Gas Guidelines

MMS's Royalty Policy Board (Board) issued guidelines for valuing and reporting coalbed gas (coalbed methane) on December 7, 1995 (Attachment 9). The guidelines were

communicated to leases by Dear Operator/Payor letter of April 22, 1996 (Attachment 10).

The Board promulgated the coalbed gas guidelines in large part to address the CO_2-removal costs. Based on the regulations at 30 CFR § 206.158(d)(1), the Board concluded that no processing allowance may be claimed for extracting CO_2, unless the CO_2 is marketed and sold.[3] The Board further stated:

> From the data the coalbed methane producers submitted to MMS, it does not appear that (the CO_2 extraction) warrants an extraordinary processing allowance and the amine process is not extraordinary when compared to the kinds of processing in the overall industry. Therefore, under 30 CFR § 206.158(d)(2)(i), the costs of extracting the CO_2 from the methane generally would not appear to qualify for an extraordinary processing allowance and also should not be included in the transportation allowance allocated to the methane.

Payor Handbook

The *Oil and Gas Payor Handbook, Volume III*, which was written to explain more fully the intent and application of the valuation regulations, also provides guidance in this case. In addressing the marketable-condition regulations in 30 CFR § 206.158(d)(1), and specifically the clause regarding nonroyalty-bearing production, the handbook indicates that unsalable CO_2 is not royalty bearing and as such is not permitted a processing allowance (p. 7-2).

EFFECT OF REGULATIONS

Processing allowances are applicable only against the value of gas plant products, unless MMS grants an extraordinary

---

[3] The Board did note that the costs associated with CO_2 extraction may be claimed as processing allowance against the value of CO_2 to the extent the CO_2 is marketed and sold at a later date.

processing cost allowance (30 CFR § 206.158(c)(1)). The definition of "gas plant product" at 30 CFR § 206.151 is predicated on the product being marketable. Merriam-Webster's Collegiate Dictionary, Tenth Edition (1996), defines "marketable" as "fit to be offered for sale in a market," "wanted by purchasers or employers: SALABLE," and "of or relating to buying or selling."

At the outset it appears the extracted CO_2 does not qualify as a gas plant product because it is not marketable; it is vented because there is no market for it. Accordingly, CO_2 has no value against which to apply a processing allowance. Thus, the provisions of 30 CFR § 206.158(d)(1) addressing sweetening and nonroyalty production, in combination with 30 CFR §§ 206.158(b) and 206.158(c)(1), would appear to prohibit a processing allowance in this case. In view of the language in 30 CFR § 206.158(d)(2)(i) stating that extraordinary processing cost allowances are in addition to any other processing allowance to which the lessee is entitled, it would further appear that an extraordinary processing cost allowance is not warranted when a processing allowance is not applicable. In other words, because CO_2 in this case is not even eligible for a processing allowance, an extraordinary processing cost allowance is not proper.

Vastar points out, however, that MMS has granted an extraordinary processing cost allowance in a similar situation where CO_2 is vented and not marketed, referring to MMS's approval for Louisiana Land and Exploration Company's (LL&E) Lost Cabin Gas Plant (SOR at p. 4). Under 30 CFR § 206.158(d)(2)(i), the lessee must show that its costs are extraordinary, unusual, or unconventional by reference to standard industry conditions and practice to be eligible for an extraordinary processing cost allowance. The remainder of this report will show that Vastar's costs are not extraordinary, unusual, or unconventional.

ARGUMENTS

1. Whether the composition of the gas stream is atypical when compared to conventional gas is subjective. Although composition will dictate the processes used to remove elements or compounds from a gas stream, composition by and of itself is not a sufficient criterion to grant an extraordinary processing cost allowance. *In fact, regulations provide that cost, not composition, is the determining factor in granting an extraordinary processing cost allowance.*

Vastar's Position

The main thrust of Vastar's arguments revolves around the composition of the coalbed gas entering the Val Verde Plant. Vastar contends this gas is "atypical" because it contains no liquid hydrocarbons and has a high CO_2 content. Thus, Vastar believes it satisfies the criteria for an extraordinary processing cost allowance as given in MMS's guidelines.[4] It argues that MMS erred in rejecting the gas as unusual for the following reasons (SOR for MMS-97-0191-O&G at p. 2):

- MSS ignores its own definition of "atypical" gas in Chapter 7.1.2 of the Oil and Gas Payor Handbook, Volume III, which states, "'Atypical' gas is defined as gas that does not contain liquefiable hydrocarbons, such as ethane, propane, butane, etc."
- MMS cited the lack of liquids as evidence supporting the extraordinary processing cost allowances granted

---

[4] Vastar initially claimed in its allowance application that its coalbed gas is "unique," largely by reference to Exhibits 3 and 4 of Attachment 3. These exhibits were prepared by a group of coalbed gas producers in the San Juan Basin and presented to MMS for consideration in granting allowances. They are the same reports reviewed by the Royalty Policy Board in reaching its December 7, 1995, decision on coalbed gas valuation and reporting.

for LL&E's Lost Cabin Gas Plant and Exxon Corporation's LaBarge Gas Plant.

- Statistical evidence shows this gas to be compositionally noncomparable with other natural gas streams produced in the Lower 48 States.

RVD's Position

The composition of the gas stream alone does not automatically qualify a lessee for an extraordinary processing cost allowance. Under the regulations, cost is the ultimate allowance determinant. Gas composition is a factor in determining the eligibility for an extraordinary processing cost allowance primarily because composition will dictate in some manner the processing methods and plant design necessary to process the gas. Processing methods and plant design in turn effect costs.

As we discussed in our denial decisions (Attachment 2, p. 3 of Enclosure 1), natural gas exhibits a broad spectrum of compositions. We do not argue that Vastar's coalbed gas is distinguishable from non-coalbed gas, commonly referred to as "conventional" gas.[5] (We again note that Vastar does not submit its gas composition but instead refers to the composition of the commingled gas stream entering the Val Verde Plant. See footnote 1 for average gas compositions in Vastar's area of operations.) We do have a problem with classifying this gas as unique or atypical given the spectrum of gas compositions. Each gas stream has its own set of peculiarities that makes it different or distinguishable from another gas stream. Statistical analyses can be used to categorize gas streams by showing that certain hydrocarbon compositions or concentrations of impurities are more or less common than others. Based on the statistical

---

[5] "Conventional" is a word commonly used to distinguish coalbed gas from other, non-coalbed gas streams. It has no formal meaning that we can find.

analysis presented in Vastar's SOR, the coalbed gas entering the Val Verde Plant is certainly distinguishable from other natural gas streams. But we don't agree that this distinction alone qualifies Vastar for an extraordinary processing cost allowance. Returning to 30 CFR § 206.158(d)(2)(i), it is the extraordinary, unusual, or unconventional cost of a processing operation that determines an extraordinary processing cost allowance.

The coalbed gas entering the Val Verde Plant is essentially dry gas; i.e., it contains negligible liquid hydrocarbons, with a relatively large amount of CO_2. However, the lack of liquid hydrocarbons as argued by Vastar, does not make it unusual or atypical. Dry gas production is neither atypical nor uncommon. For example, much of the "conventional" gas produced in central and northern Montana is dry gas. Furthermore, the definition of "atypical" on pa. 7-2 of the *Oil and Gas Payor Handbook, Volume III*, is not a formal one. Noteworthy here is the handbook's following sentence on p. 7-2, which instructs that the lessee must not only show the raw gas stream is atypical, but also the processing costs are extraordinary, unusual, or unconventional by reference to standard industry conditions and practice.

In summary, any argument that centers on gas composition to qualify for an extraordinary processing cost allowance is misplaced by being contrary to regulation.

2. *The amine process used to extract CO_2 at the Val Verde Plant is not extraordinary, unusual, or unconventional. It is widely used throughout the gas processing industry to remove acid gases.*

Vastar's Position

In its SOR for MMS-97-0063-O&G (p. 17), Vastar contends that the Val Verde Plant is more complex than conventional gas plants for the following reasons:

- The amine process used to extract CO2 uses a greater percentage of amine.

- The Val Verde Plant uses stainless steel in certain areas, rather than carbon steel.
- The Val Verde Plant requires larger amounts of water.

RVD's Position

As explained in our denial decision (Attachment 2, p. 4 of Enclosure 1), we do not view Val Verde's amine process as unconventional or extraordinary. We believe our analysis in that decision adequately supports our position. To both summarize and elaborate on that analysis:

- Amine solutions have been the generally accepted solvent to remove acid gases from natural gas streams. To our knowledge almost 80 percent of the gas plants in the United States use the amine process.
- Amine solutions are often specifically formulated and mixed with varying amounts of water to treat a given acid gas concentration. Besides the formulation used by Val Verde, there are at least eight other amine formulations, some more complex than others, available to the gas processing industry. The formulation used at Val Verde merely pushes the envelope of amine solutions.
- The principal design and equipment for the amine process (contactor towers, regeneration units, pipes, pumps, and controls) are much the same for both coalbed and conventional gas plants. In fact, Val Verde's amine trains 1 and 2 were purchased and used from an out-of-state, conventional gas treating facility and installed at their present location. The use of stainless steel is not uncommon when handling acid gases.
- The fact that the Val Verde Plant requires larger amounts of water is probably due in large part to its size and capacity. Val Verde consists of eight standalone treating plants, or "trains," with a total capacity

of 800 MMscf/d. Water is used in making up the amine solutions and rehydrating the methane. Vastar does not indicate the amount of water used on a unit basis or how this amount compares to other plants.

3. *Vastar does not demonstrate its unit costs to be extraordinary.*

Vastar's Position

In its SOR for MMS-97-0063-O&G (p. 17), Vastar claims its cost to remove CO_2 from the coalbed gas ($0.0778/Mcf) is significant.

RVD's Position

Under the regulations, cost is the ultimate determinant in granting an extraordinary processing cost allowance. Vastar does not offer any analysis to demonstrate that its cost is extraordinary, unusual, or unconventional by reference to standard industry conditions and practice, as required by 30 CFR § 206.158(d)(2)(i); it simply claims that its cost is significant.

As we indicated in our denial decision (Attachment 2, p. 5 of the Enclosure 1), Vastar's cost is considerably less than the costs for which MMS has previously granted extraordinary processing cost allowances. In fact, based on proprietary information submitted in support of other extraordinary processing cost allowance applications,[6] Vastar's cost at $0.0778/Mcf is at the law end of the range for CO_2-removal costs.

4. *The composition of the gas stream and processing techniques at Exxon Corporation's LaBarge Plant (118 IBLA 221, 1991) are distinguishable from those at the Val Verde Plant.*

---

[6] We specifically refer to a proprietary report prepared for LL&E by Purvin & Gertz, Inc. MMS is not at liberty to release this report. Should Vastar wish to review this report, we recommend they contact LL&E directly for its release.

Vastar's Opinions

Vastar believes that Val Verde is in many ways compared to the LaBarge system at issue in *Exxon Corp.*, for which MMS has granted an extraordinary processing cost allowance. Claimed similarities include the high levels of CO_2 and lack of liquid hydrocarbons on both gas streams. (See SOR for MMS-97-0063-O&G at p. 17.) Vastar also contends the CO_2 removal process at Val Verde is, in some respects, more sophisticated than the process at LaBarge; where LaBarge uses a largely physical process to remove CO_2. Val Verde uses a chemical process.

RVD's Commentary

Any comparison with *Exxon Corp.* to support an extraordinary processing cost allowance would appear moot given that Vastar has not demonstrated its cost to be extraordinary, unusual, or unconventional. Nonetheless, we assert there are distinct differences between LaBarge and Val Verde, differences that would not support an extraordinary processing cost allowance for Val Verde.

As discussed above, any argument centering on gas composition to support an extraordinary processing cost allowance is misplaced; gas composition is not the sole, or even compelling, factor in granting such an allowance. We do not believe the lack of liquid hydrocarbons makes Vastar's gas necessarily atypical. As for CO_2, the gas entering the LaBarge Plant contains 65.4 percent CO_2, more than five times the amount of CO_2 entering the Val Verde Plant.

As for processing techniques, we've indicated that the basic amine process used at Val Verde is used by almost 80 percent of the gas plants in the United States, the primary difference being in the formulation of the amine solution. In contrast, the Selexol process used at LaBarge is, to our knowledge, used in only four other gas plants in the country.

Finally, and perhaps most important, a market exists for the CO_2 extracted at LaBarge. Thus, the CO_2 at LaBarge has value and is eligible for a processing allowance, making an extraordinary processing cost allowance proper in this case for the unrecovered costs of extracting CO_2.

5. *RVD's application denial is consistent with governing regulations.*

Vastar's Allegation

Vastar contends that RVD's application denial is so inconsistent with prior interpretation of the regulations and guidelines as to be arbitrary and capricious. Citing *U.S. Oil and Refining Co.*, 137 IBLA 223, 232 (1996) and *Union Oil Co. of California*, 116 IBLA 8, 16 (1990), Vastar alleges that RVD's decision is not supported by a rational basis.

RVD's Commentary

We did indeed analyze Vastar's application in review of the governing regulations (Attachment 2). We believe the rationale given in our decision, as well as our arguments given here, are consistent with the regulations.

The underlying thrust of Vastar's appeal appears to be a challenge to the Board's guidelines on coalbed gas valuation. The Board constructed those guidelines also in view of the regulations after lengthy deliberation. Our analysis and arguments given here support those guidelines.

ADDITIONAL SUPPORT OF RVD'S POSITION

Although we have avoided the issue of marketable condition in this report, it is inherent in our arguments and explicitly raised as an issue in Vastar's SOR for MMS-97-0063-O&G (p. 9). IBLA has addressed a similar situation regarding the fees levied by a processor for sweetening sour gas in *Texaco Inc.*, 134 IBLA 109 (1995), only in this case the extracted contaminant was hydrogen sulfide instead of CO_2. The processor, Colorado Interstate Gas Company, charged Texaco $0.998/Mcf to sweeten Texaco's sour gas. MMS

disallowed a deduction for the sweetening costs on the grounds that such costs were for the purpose of making the production marketable. In deciding Texaco's appeal, IBLA concluded in pertinent part:

> A Federal oil and gas lessee's duty to put gas produced from the lease into a marketable condition includes sweetening sour gas by removing hydrogen sulfide, and the costs for such treatment are not deductible from the value of the production for royalty computation purposes no matter who performs the treatment or whether title to the gas passes before the sweetening occurs.

The Wyoming District Court affirmed IBLA's decision in *Texaco Inc. v. Quarterman* (96-CV-08-J, 1997).

This decision supports our position that Vastar's gas is ineligible for a processing allowance. It then follows that Vastar's gas is also ineligible for an extraordinary processing cost allowance. Vastar's costs compared to Texaco's are further evidence that an extraordinary processing cost allowance is not warranted in the instant case.

SUMMATION

Based on the foregoing, we submit that Vastar is not eligible for an extraordinary processing cost allowance for the following reasons:

1. Regulations at 30 CFR § 206.158(d)(1) prohibit a processing allowance when extracted products are not marketable. Accordingly, an extraordinary processing cost allowance is inappropriate under 30 CFR § 206.158(d)(2)(i).
2. Assuming, arguendo, that 30 CFR § 206.158(d)(2)(i) might permit an extraordinary processing cost allowance, Vastar has not demonstrated that its costs are extraordinary, unusual, or unconventional by comparison to standard industry conditions and practice.

We are sending a copy of this memorandum to Vastar. If you have any questions on this matter, please call Mr. Charles Brook at (303) 275-7250.

Attachments

APPENDIX H

[Seal Omitted]

United States Department of the Interior

MINERALS MANAGEMENT SERVICE

Royalty Management Program
P.O. Box 25165
Denver, Colorado 80225-0165

MMS/SICD 7-4-10
MS 3660 93-60032.588

CERTIFIED MAIL –
RETURN RECEIPT REQUESTED May 27, 1997

Mr. Jim Shearrer
Supervisor, Audit Coordinator
Amoco Production Company
P.O. Box 591
Tulsa, Oklahoma 74102-0591

RECEIVED
June 10, 1997
Law Dept.
Denver, Colorado
Amoco Corporation

Dear Mr. Shearrer:

The New Mexico Taxation and Revenue Department (State), Oil and Gas Audit Section, has been delegated the authority by the Secretary of the Interior to perform audits and related investigations of Federal Oil and Gas leases located in New Mexico. This authority is in accordance with Section 205 of the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA). In this capacity the State has conducted a review of the Amoco Production Company (Amoco) policies regarding royalty calculations associated with sales of coalbed methane gas produced from Federal leases located in the San Juan Basin, New Mexico, during the period January 1, 1989, through December 31, 1996. The review was performed to determine whether additional royalties are due on coalbed methane proceeds associated with Federal leases. Our review disclosed that you have incorrectly calculated gross proceeds on these sales and as a

result, we have determined that additional royalties are due in the amount of $4,117,607.

Coalbed methane gas is produced from coal formations and as a result it has a higher content of carbon dioxide (CO_2). The content of the CO_2 can vary from minimal amounts to as much as 12 to 15 percent. In order to transport and sell the coalbed methane, the CO_2 level has to be reduced to around 2 to 3 percent. This requires that the coalbed methane be transported from the wellhead to a processing facility. Costs associated with the movement and processing of this gas include gathering, compression, dehydration and CO_2 removal. Producers are charged a fee by plant operators for performing these services. Based on our review, these charges were not considered by Amoco in determining the gross proceeds value for computing royalties.

The following discussion outlines the allowable as well as non-allowable deductions that may be utilized in the calculation of royalty value for coalbed methane.

Coalbed methane and associated products is valued in accordance with 30 CFR § 206.152 (1988). The value of coalbed methane is the gross proceeds accruing to the lessee under an arm's-length transaction for the sale of the gas including the costs of placing the gas in marketable condition. In the case of a non-arm's-length contract, value is determined based on the higher of gross proceeds or the valuation benchmarks at 30 CFR § 206.152(c). The value for royalty purposes also includes applicable allowances.

Allowable Deductions:

Transportation allowances are granted for the reasonable, actual necessary costs of transporting the coalbed methane from the royalty measurement point (either the well or the Central Delivery Point (CDP)) to the point of sale remote from the lease. The transportation allowance allocated to the coalbed methane should be calculated according to 30 CFR §§ 206.156 and 206.157 (1988). It may include the

costs of transporting the methane and the portion of the CO_2 permitted in the pipeline specifications. For example, if the pipeline specifications allowed 3 percent CO_2, the lessee will be allowed to include in the transportation allowance the costs of transporting 3 percent of the CO_2 volume.

Large quantities of water along with low quantities of gas are normally produced initially from coalbed methane wells. The resulting dehydration costs which occur prior to the royalty measurement point are not deductible. Dehydration costs occurring after the royalty measurement point are deductible as part of the transportation allowance.

Production from coalbed methane wells is enhanced by lowering wellhead pressure. Once produced, the pressure must be increased to move the gas down the line to the processing facility. The cost required to move coalbed methane would therefore be greater than normal because now additional compression is required to make up for the initial reduction in wellhead pressure utilized to enhance recovery. That portion of the compression costs incurred to enhance production of coalbed methane is not allowable. To the extent the producer can demonstrate that all or a portion of the compression costs are not necessary for enhanced recovery, that portion may be allowable as part of transportation.

In determining the transportation allowance for both arm's-length and non-arm's-length situations, the lessee has the burden to demonstrate what portion of the costs are attributable to transportation.

The costs of extracting the CO_2 cannot be included as part of a transportation allowance.

Processing Allowance/Extraordinary Processing Allowances:

Based on the regulations at 30 CFR § 206.158(d) (1) (1988), when gas is processed for the removal of acid gases, com-

monly referred to as sweetening, no processing cost deduction is allowed for such costs unless the acid gases removed are further processed into a gas plant product. Because the CO_2 is vented to the atmosphere, no processing allowance may be claimed for extracting the CO_2 from the coalbed methane. Based on data examined by the Minerals Management Service (MMS), the costs of extracting the CO_2 from the coalbed methane do not qualify for an extraordinary processing allowance.

Other Non-allowable Deductions:

Gathering from the wellhead to the CDP when the Bureau of Land Management has approved the CDP as the point of royalty settlement is not an allowable deduction.

Wellhead separation costs are not an allowable deduction from the value of the coalbed methane.

The State sent Amoco an Issue letter dated November 16, 1995, that identified two issues relating to the San Juan 30-6 Unit coalbed methane Agreement #891-000538-A. The Issues were 1) under-reported volumes for the Agreement and 2) the methodology used to value the gas produced from the Agreement.

Pricing Methodology:

Burlington Resources/Meridian Oil Inc. is the operator of the San Juan 30-6 Unit for Agreement #891-000538-A. Most of the gas is gathered and transported on a system owned by Meridian's affiliate, Meridian Oil Gathering Inc. (MOGI) commonly referred to as the Val Verde System. This system is designed to transport coalbed methane gas to their processing facility and then to the El Paso Natural Gas mainline transportation system. MOGI's processing facility is used strictly to separate the CO_2 and make the gas marketable. In Amoco's reporting on their leases, the price reported is net of deductions taken for gathering, treating and removal of the CO_2 from the gas stream.

In 1995 producers in the San Juan Basin of New Mexico that produce coalbed methane gas, requested MMS to consider allowing certain costs as a transportation allowance or as an extraordinary processing costs to be deductions from the value of the methane. By letter dated December 7, 1995, the Royalty Policy Board (RPB) issued the Coalbed Methane Valuation and Reporting Guidelines as outlined above. The RPB disallowed the costs to remove the CO_2 from the gas stream and disallowed the cost to transport the CO_2 volumes to the processing or treating facility, with an adjustment for the amount of CO_2 allowed by the major pipeline transporters.

The State has applied the regulations and guidelines in the MMS/RPB letter of December 7, 1995, to calculate the royalties for the San Juan 30-6 Unit as follows:

> By letter dated December 19, 1995, the State requested Amoco to provide a breakdown of costs associated with transporting the coalbed methane to a processing plant. Amoco's response was based on information received from Meridian by letter dated May 29, 1996, that indicated a cost of the CO_2 removal to be $0.778 per MCF.

The State applied the following regulations, guidance and decisions to determine the allowable transportation rate that is applied only to the royalty bearing portion of the-full gas stream collected at the CDP's. The transportation allowance allocated to the coalbed methane gas must be calculated in accordance with 30 CFR §§ 206.156 and 206.157 (1988).

30 CFR § 206.157(2) (i) states:

> If an arm's-length transportation contract includes more than one product in a gaseous phase and the transportation costs attributable to each product cannot be determined from the contract, the total transportation cost shall be allocated in a consistent and

> equitable manner to each of the products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, *no allowance may be taken for the costs of transporting lease production which is not royalty bearing without MMS approval.* [Emphasis added.]

The State broke the costs into two parts, disallowed CO_2 removal, and disallowed transportation of CO_2. The disallowed CO_2 removal rate is calculated by multiplying Amoco's total unit volumes by the $.0778 per MCF rate indicated in the Meridian letter as the cost to remove the CO_2 at the Val Verde Plant. The disallowed transportation of the CO_2 is calculated by taking Amoco's total unit volumes by the CO_2 percentage in the gas stream adjusted for the CO_2 percent allowed by the major pipeline transporters (2 percentage was used in this audit). The volume is then multiplied by the transportation portion in the contract rate to transport the CO_2 volumes from the field (CDP) to the processing facility. The CO_2 percentage used in these calculations is the percentage of CO_2 at the inlet of the Val Verde Plant, as provided by Meridian, ranging from 10.8000% in December 1988 to 12.2000% for December 1995 as shown on Schedule F. The Transportation rate used from January 1989 through October 1990 is ($.395 - $.0778 = $.31720). From November 1990 through December 1996 the rate is ($.3600 - $.0778 = $.2822). The State was provided with Unit total Volumes from January 1992 through December 1996. The State has calculated Amoco's royalties through December 1996 for the San Juan 30-6 in the amount of $432,158 (Schedule A).

Amoco is a working interest owner and lessee in the Northeast Blanco Unit (NEBU) that is operated by Blackwood Nichols (BN). Through an arrangement with the working

interest owners in the unit, BN reported and paid royalties on Amoco's behalf. On July 9, 1996, the State sent BN a letter regarding the NEBU coalbed methane gas issue. The letter also addressed the interest of Amoco and the other working interest for which BN reported and paid royalties. By letter dated September 3, 1996, Amoco requested that the findings relating to the NEBU on coalbed methane gas be addressed directly to Amoco. By letter dated September 9, 1996, the State notified Amoco the NEBU would be combined with all of Amoco's coalbed gas issues in the San Juan Basin.

On October 15, 1996, the State received a response from Amoco. The letter stated that the removal of CO_2 from coalbed gas should be permitted as a transportation expense or extraordinary processing costs. The letter further stated that MMS should grant an alternative method of valuation from coalbed gas produced from Federal lands. These comments have been incorporated into the body of this letter, along with responses. Our audit addresses the issue using regulations in effect at the time of the gas production subsequent interpretation by MMS.

The State's audit of the NEBU covered the period May 1990 through December 1993. For this period, Amoco's coalbed gas sales from the NEBU and other San Juan Basin leases (except the San Juan 30-6) was going to Williams Field Services. By letter dated May 20, 1996, the State requested Amoco to provide copies of transportation and treating contracts for the period January 1989 through December 1995 from Meridian on the Val Verde System, and from Williams for the period July 1992 through December 1995 for the Milagro and Manzanares Systems. The State also requested Amoco to provide the volumes going through each system for this 1989 through 1995 period. Amoco provided Contract #143-063 – *Discounted Coal Seam Gathering, Treating, and Transportation Rates*

and Purchase Obligation dated June 15, 1990, and Letter Agreement dated February 13, 1990. Amoco and Conoco entered into this agreement with Williams for the purpose of Northwest/Williams to purchase, gather, treat and/or transport Amoco's and/or Conoco's coalseam gas on an interim basis and the construction and operation of certain new Williams facilities (Trunk S – Manzanares & Milagro Treating Facility) for the purpose of gathering, dehydrating, treating and transporting coalseam gas from the 30-8 area and the NEBU in the San Juan Basin of New Mexico on to El Paso Natural Gas Company mainline near Bloomfield, New Mexico. The rate for service for gas processed by Williams Ignacio Plant in Colorado is $.30/MCF. The components of this rate are $.1353/MCF for gathering, *$.0795/MCF for treating*, and $.0852/MCF for transportation. This rate is used for the period February 1990 through June 1992 for all of Amoco's coalseam gas going through Ignacio. Williams, in a letter to producers dated May 1, 1996, indicated that 21% of their contract rate for the Manzanares System is for treating and removal of CO_2 and the balance is for transportation.

From July 1992 to December 1995, Amoco provided schedules of their coalbed methane gas going through Williams new Manzanares and Milagro Treating Facility. For the NEBU, Amoco indicated that Williams was charging the following rates for each CDP: Sims $.26, Pump $.30, and Middle $.30. Amoco also provided the State with CO_2 percentages for the test months for each property. Amoco indicated that some gas from the NEBU went to Meridian's Val Verde Plant during this period. The State re-calculated royalties for the NEBU for the period January 1990 through December 1995 using the volumes for each transportation system as provided by BN and Amoco. For volumes going through Ignacio and Milagro, the State used the CO_2 percentage at the CDP's as provided by BN. For volumes going through Val Verde, the State used the CO_2

percentages at the Plant inlet as provide by Meridian. The State calculated additional royalties due for the disallowed cost of removal of the CO_2 and the transportation of the CO_2 volumes for the NEBU for the period January 1990 through December 1995 in the amount of $1,308,372 (Schedule D).

For Amoco's other coalbed methane volumes going through the Manzanares System, the State calculated the disallowed costs for the period July 1992 through December 1995, using the volumes provided by Amoco and the CO_2 percentage at each meter as provided by Amoco. The CO_2 percentage has been adjusted for a 2% allowable by the mainline pipeline transporter. The State calculated additional royalties in the amount of $2,170,962 (Schedule C).

For Amoco's coalbed methane volumes (other than San Juan 30-6 and NEBU) going through the Val Verde Plant, the State used the volumes provided by Amoco, the treating and removal rates as provided by Coopers and LyBrand, and used the CO_2 percentage at the Plant inlet as adjusted for 2% as provided by Meridian. The State calculated additional royalties due for the period October 1992 through December 1995 or $206,115 (Schedule C-1).

The value used by Amoco in its royalty calculations included volumes which had been reduced by non-allowable deductions. Amoco's failure to calculate gross proceeds utilizing only allowable deductions as noted above has resulted in an underpayment of royalties. Therefore, in order to bring royalty payments into compliance with the aforementioned regulations and decisions, Amoco is directed to pay additional royalties of $4,117,607 as presented in the attached schedules. *Payment must be mailed to the address indicated on the enclosed bill, and must be made payable to the U.S. Department of the Interior, MMS and must be received by the invoice date.* To ensure proper credit to your account, please include your payment and the remit-

tance copy of the bill for collection. In order to simplify the billing process, MMS has calculated and accumulated royalty underpayments into Federal Lease No. 029-012293-0. However, Amoco will still be required to submit separate lines of Form MMS-2014 for each lease and sales month. Your payment should be tendered in accordance with the regulations at 30 CFR § 218.51 (1996) and accompanied by an appropriately completed *green* Form MMS-2014 (forms and instructions enclosed) using adjustment reason code *40*. The green form MMS-2014 must reflect *650118* in block *3a* "Payor Assigned Document Number."

The State has identified a consistent and systemic error in the reporting and paying of royalties from the various leases in the San Juan Basin of New Mexico. Therefore, Amoco is ordered to perform the following compliance actions within 90 days of receipt of this letter:

1. Identify any other Federal and Indian leases not included above, for which Amoco is the responsible payor or lessee, and where coalbed methane is produced in the San Juan Basin.
2. For all leases identified in (1), re-calculate and pay the additional royalties due in accordance with the guidelines outlined above for all periods from January 1989 through August 1996. (If you are unable to identify and segregate the various costs in order to insure that only allowable costs have been deducted in arriving at the proper value for royalties, then the MMS will assist you in determining the allowable deductions.)
3. For all leases included in the attached schedules (other than San Juan 30-6), re-calculate and pay the additional royalties due in accordance with the guidelines outlined above for all periods from January 1996 through August 1996.
4. All supporting calculations and source documents are subject to audit by MMS, therefore, should be re-

tained by Amoco until MMS completes its follow-up compliance testing.

Appropriate late payment charges pursuant to 30 CFR § 218.102 (1996) will be computed and billed to Amoco upon receipt of payment of the additional royalties due.

Royalty calculations subsequent to the current production month must also be in compliance with regulatory determination referred to in this order. If in the future, we determine that the required recomputations have not been performed and future royalty payments do not comply with this order, the violations may be considered willful.

A copy of your payment and green Form MMS-2014 should be sent to:

Mr. Jay Norman, Supervisor
Taxation and Revenue Department
Oil and Gas Audit Section
Manuel Lujan Building
1200 South St. Francis Drive
Santa Fe, New Mexico 87509

Section 109 of FOGRMA, promulgated in 30 CFR § 241.51 (1996), authorizes MMS to assess civil penalties for failure or refusal to comply with the requirements of FOGRMA or any statute, regulation, rule, order, or permit. Consequently, your failure to comply with the terms of this order may be considered a violation pursuant to 30 CFR § 241.51, and could subject you to penalties of up to $5,000 per violation per day for each day such violation continues and up to $10,000 per violation each day if the violation is considered to be willful.

You have the right to appeal in accordance with the provi

sions of 30 CFR Part 290 (1996). Any appeal taken will be to the Director, MMS, and the notice of appeal must be filed within 30 days from the date of receipt of this order with:

Mr. James R. Detlefs, Chief
Minerals Management Service
State and Indian Compliance Division
P.O. Box 25165, MS 3660
Denver, Colorado 80225-0165

Any notice of appeal shall incorporate or provide by separate letter written statements of reasons, as you deem adequate, to justify reversal or modification of this directive. You have 60 days from receipt of this letter to file any statements of reasons or written brief to explain your appeal. This filing requirement runs concurrent with the requirement to file the appeal. If the filing requirement for statements of reasons cannot be fulfilled within 60 days of the receipt of the order, an extension of time to file statements of reasons must be obtained. Time extensions for filing the statements of reasons will not be authorized unless requested in writing with justification showing good cause for the time extension. Further, the written request for the time extension must be provided to the Division Chief at the address shown above for approval.

In accordance with the provisions of 30 CFR § 243.2 (1996), compliance with order will be suspended upon the posting of an adequate surety pending the outcome of the appeal. The surety must be received at MMS by the due date. The surety must be in the amount of $5,959,300 which includes the principal plus interest that will accrue through March 31, 1998. Upon request by MMS, the amount of the surety will be increased periodically, if necessary, to cover any additional interest that may accrue. Enclosed are instructions for posting the surety.

If you have any questions, please contact Mr. Jay Norman of the State at (505) 827-0986, or Ms. Carol Green of MMS at (303) 275-7459.

Sincerely,

/s/ James R. Detlefs
James R. Detlefs
Chief, State and Indian
Compliance Division

8 Enclosures

cc: Mr. Jay Norman
Taxation & Revenue Department
Oil and Gas Audit Section
Manual Lujan Building
1200 South St. Francis Drive
Santa Fe, New Mexico 87502

APPENDIX I

[Seal Omitted]

United States Department of the Interior

MINERALS MANAGEMENT SERVICE

Royalty Management Program
P.O. Box 25165
Denver, Colorado 80225-0165

January 22, 1997

MMS/SICD 7-11-22
MS 3660

3-40001.562

Received /28/97

CERTIFIED MAIL --
RETURN RECEIPT REQUESTED

Mrs. Mary Holman
PRC-C5128
The Atlantic Richfield Company
2300 West Plano Parkway
Plano, Texas 75075

Re: Royalties on Coalbed Methane Agreement #891-000538-A

Dear Mrs. Holman:

The New Mexico Taxation and Revenue Department's (State), Oil and Gas Audit Section has been delegated the authority by the Secretary of the Interior to perform audits and related investigations of Federal Oil and Gas leases located in New Mexico. This authority is in accordance with Section 205 of the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA). In this capacity the State has conducted a review of The Atlantic Richfield Company (ARCO), regarding royalty calculation policies associated with sales of coalbed methane gas produced from Federal leases located in the San Juan Basin of New Mexico,

specifically the San Juan 30-6 Unit, located in Rio Arriba County. The review was performed to determine whether additional royalties are due on coalbed methane proceeds associated with Federal leases. Our review disclosed that you have incorrectly calculated gross proceeds on these sales and as a result, we have determined that additional royalties are due.

Coalbed methane gas is produced from coal formations and as a result it has a higher content of carbon dioxide (CO_2). The content of the CO_2 can vary from minimal amounts to as much as 12 to 15 percent. In order to transport and sell the coalbed methane, the CO_2 level has to be reduced to around 2 to 3 percent. This requires that the coalbed methane be transported from the wellhead to a processing facility. Costs associated with the movement and processing of this gas include gathering, compression, dehydration and CO_2 removal. Producers are charged a fee by plant operators for performing these services. Based on our review, these charges were not considered by ARCO in determining the gross proceeds value for computing royalties.

The following discussion outlines the allowable as well as the non-allowable deductions that may be utilized in the calculation of royalty value for coalbed methane.

Coalbed methane and associated products should be valued in accordance with 30 CFR §206.152 (1988). The value of coalbed methane is the gross proceeds accruing to the lessee under an arm's-length transaction for the sale of the gas including the costs of placing the gas in marketable condition. In the case of a non-arm's-length contract value is determined based on the higher of gross proceeds or the valuation benchmarks at 30 CFR §206.152(c). The value for royalty purposes also includes applicable allowances.

Allowable Deductions:

Transportation allowances are granted for the reasonable, actual necessary costs of transporting the coalbed methane

from the royalty measurement point (either the well or the Central Delivery Point (CDP)) to the point of sale remote from the lease. The transportation allowance allocated to the coalbed methane should be calculated according to 30 CFR §§ 206.156 and 206.157 (1988). It may include the costs of transporting the methane and the portion of the CO_2 permitted in the pipeline specifications. For example, if the pipeline specifications allowed 3 percent CO_2, the lessee will be allowed to include in the transportation allowance the costs of transporting 3 percent of the CO_2 volume.

Large quantities of water along with low quantities of gas are normally produced initially from coalbed methane wells. The resulting dehydration costs which occur prior to the royalty measurement point are not deductible. Dehydration costs occurring after the royalty measurement point are deductible as part of the transportation allowance.

Production from coalbed methane wells is enhanced by lowering wellhead pressure. Once produced, the pressure must be increased to move the gas down the line to the processing facility. The cost required to move coalbed methane would therefore be greater than normal because now additional compression is required to make up for the initial reduction in wellhead pressure utilized to enhance recovery. That portion of the compression costs incurred to enhance production of coalbed methane is not allowable. To the extent the producer can demonstrate that all or a portion of the compression costs are not necessary for enhanced recovery, that portion may be allowable as part of transportation.

In determining the transportation allowance for both arm's-length and non-arm's-length situations, the lessee has the burden to demonstrate what portion of the costs are attributable to transportation.

The costs of extracting the CO_2 cannot be included as part of a transportation allowance.

Processing Allowances/Extraordinary Processing Allowances:

Based on the regulations at 30 CFR § 206.158(d) (1) (1988), when gas is processed for the removal of acid gases, commonly referred to as sweetening, no processing cost deduction is allowed for such costs unless the acid gases removed are further processed into a gas plant product. Because the CO_2 is vented to the atmosphere, no processing allowance may be claimed for extracting the CO_2 from the coalbed methane. Based on data examined by the Minerals Management Service (MMS), the costs of extracting the CO_2 from the coalbed methane do not qualify for an extraordinary processing allowance.

Other Non-allowable Deductions:

Gathering from the wellhead to the CDP when the Bureau of Land Management (BLM) has approved the CDP as the point of royalty settlement is not an allowable deduction.

Wellhead separation costs are not an allowable deduction from the value of the coalbed methane.

At the request of the Farmington, New Mexico office of the BLM, the State performed an audit of the San Juan 30-6 Unit for the period January 1, 1989, through December 31, 1991. The BLM had identified that volumes were not being reported correctly for Agreement #891-000538-A. All production from this Agreement is coalbed methane gas. During the audit period there were 19 different revisions to this Agreement (revisions 12 through 30). The thirtieth revision was approved in October 1993 with an effective date of July 1, 1991. The State's review of transporter statements from El Paso Natural Gas (EPNG) and from Northwest Pipeline (NWPL)/Williams Field Services (WFS) indicated that 217,310,320 MCF had been trans-

ported from the unit wells for this audit period. The State confirmed BLM's position that 100 percent of the unit production was not being reported on Forms MMS-2014. According to MMS, ARCO is a royalty payor and lessee for the following leases under this Agreement. Tract 25 Lease #029-003385-0, Tract 26 Lease #029-003403-0, Tract 12 Lease #082-080711-0, and Tract 15 Lease #082-080712-0. All the above leases were included in revisions 12 through 30 for the audit period. The State determined that an entitlement basis should be used to bring the unit leases into compliance because this was the method used by all working interest owners in the unit.

The Oil and Gas Payor Handbook under "Allocating and Reporting Sales from Leases and Agreements" states:

> On Federal and Indian leases having an initial unit or Communitization Agreement pending, royalties should be reported and paid on 100% of sales under current lease terms until such time as the Agreement is approved. If the Agreement is approved, retroactive reporting adjustments will be required to accurately reflect allocations specified in the new Agreement.

Royalties must be based on the most current Agreement allocation schedule approved by BLM or MMS, regardless of whether the quantity allocated to the lease is less than, equal to or greater than the quantity actually sold on the lease. This accounting is compelled by language generally involved in unit and Communitization Agreements:

> All unitized/communitized substances produced from each participating area established under this Agreement, . . . shall be deemed to be produced equally on an acreage basis from the several tracts of unitized/communitized land of the participating area established for such production and, for the purpose of determining any benefits accruing under this

> Agreement, each tract of unitized/communitized land shall have allocated to it such percentage of said production as the number of acres of such tract included in said participating area bears to the total acres of unitized/communitized land in such participating area . . .

The Federal Regulations at 30 CFR § 202.150(e) (1) (1988) entitled "Royalty on Gas" stated, in part:

> . . . In those instances where the lessee of any lease committed to a Federally approved unitization or Communitization Agreement does not actually take the proportionate share of the production attributable to its Federal or Indian lease under the terms of the Agreement, the full share of production attributable to the lease under the terms of the Agreement nonetheless is subject to the royalty payment and reporting requirements of this title.

Using this methodology for each unit tract for each of the nineteen revisions the State has calculated ARCO's entitled volumes for the period January 1989 through June 1996, to be 61,866,726 MCF. By comparing this volume to the volumes reported on the Form MMS-2014 for ARCO's four leases, ARCO had underreported volumes of 1,402 MCF, however, by using the ARCO reported prices as reported on the Form MMS 2014 for these entitled volumes it appears that ARCO over-reported royalties by $45,742 (Schedule A).

Meridian Oil Inc. (MOI) is the operator of the San Juan 30-6 Unit for Agreement #891-000538-A. Most of the gas is gathered and transported on a system owned by Meridian's affiliate, Meridian Oil Gathering Inc. (MOGI) commonly referred to as the Val Verde System. This system is designed to transport coalbed methane gas to their processing facility and then to EPNG's mainline transportation

system. MOGI's processing facility is used strictly to separate the CO_2 and make the gas marketable.

For the period January 1989 through March 1992, ARCO was selling all their production to Meridian under the joint operating agreement. Since March 1992, ARCO has marketed their production under various selling arrangements.

During the period January 1989 through March 1992, ARCO's price received from Meridian was based on a sale at the wellhead to Meridian's affiliate, Meridian Oil Trading Inc. (MOTI). Based on third party information, the State has determined that the wellhead prices offered by Meridian were reduced by costs associated with transporting the gas, and the processing to remove the CO_2 from the gas stream.

The regulations at 30 CFR § 206.152(i) (1988), state, in part:

> The lessee is required to place gas in marketable condition at no cost to the Federal Government . . . unless otherwise provided in the lease agreement. Where the value established pursuant to this section is determined by the lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser . . . is providing certain services, the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition.

The State has applied the regulations and guidelines in the MMS Royalty Policy Committee letter of December 7, 1995, to calculate the royalties for the San Juan 30-6 Unit as follows:

> On January 8, 1996, the State requested ARCO to provide a breakdown of costs associated with transporting the coalbed methane gas to the processing plant, any costs of dehydration prior to the CDP and after the CDP, any costs associated with compression

> incurred to enhance production, or any compression necessary to move the gas to the processing plant, and costs associated with the removal of the CO_2 from the gas stream. ARCO's response to the State's request, was based on information received from Meridian by letter dated May 29, 1996, stated the cost of the CO_2 removal was $.0778 per MCF.

The State calculated the transportation rate and the processing rate based on the December 7, 1995, letter and the regulations. The State applied the following regulations, guidance and decisions to determine the allowable transportation rate that is applied only to the royalty-bearing portion of the full gas stream collected at the CDP's. The transportation allowance allocated to the coalbed methane gas must be calculated in accordance with 30 CFR §§ 206.156 and 206.157 (1988). 30 CFR § 206.157(2)(i) states:

> If an arm's-length transportation contract includes more than one product in a gaseous phase and the transportation cost attributable to each product cannot be determined from the contract, the total transportation cost shall be allocated in a consistent and equitable manner to each of the products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, *no allowance may be taken for the costs of transporting lease production which is not royalty bearing without MMS approval.* [Emphasis added.]

The State broke the costs into two parts: disallowed CO_2 removal, and disallowed transportation of CO_2. The disallowed CO_2 removal rate is the total rate used to extract enough CO_2 from the methane to meet pipeline contract requirements (2% was used in this audit), called the pro-

cessing rate. The disallowed transportation of CO_2 is the cost in the contract rate used to transport CO_2 volumes from the field (CDP) to the processing facility. The actual rate used by ARCO varied most months after April 1992. Schedule C calculates the actual rate used by the company and this number is used in the calculation in Schedule B. The CO_2 percentage used in these calculations is the percentage of CO_2 at the inlet of the Val Verde plant, as provided by Meridian, ranging from 10.8000% in December 1988 to 12.2000% for December 1995 as shown on Schedule D.

ARCO sent a response to the State dated September 19, 1996, in reference to the coalbed methane cost issue. They provided schedules for the San Juan 30-6 Unit leases for the period October 1989 through the month of June 1996 which indicated additional royalties due of $556,558.96. However, their schedules were calculated for just the CO_2 removal using the $.0778 treating rate with no calculation for the transportation adjustment, plus an adjustment for an overpayment of royalties for the period of $117,349.56. This overpayment was arrived at using a different price than that originally reported on the Form MMS-2014. The State has recalculated the CO_2 removal cost beginning with January 1989 and using ARCO's volumes for periods after January 1992. This calculation indicates that additional royalties are due of $601,432 (Schedule B).

The disallowed transportation amount was calculated using the entitled volumes times the average CO_2 content as provided by Meridian, allowing for the 2% pipeline quantity, to arrive at the disallowed transported volumes. We then multiplied these volumes by the difference in the total contract rate and the CO_2 removal rate. For periods January 1989 through October 1990 the rate was $.395 per MCF, for the period from November 1990 through March 1992 the rate was $.36 per MCF, and for the time period April 1992 through June 1996 the rate varied as shown in Schedule B.

This resulted in additional royalties of $226,683 (Schedule B).

In order to bring royalty payments into compliance with the aforementioned regulations and decisions, ARCO is directed to pay additional royalties of $782,373 as presented in the enclosures ($601,432 + $226,683 - $45,742). *Payment must be mailed to the address indicated on the enclosed bill, and must be made payable to the U.S. Department of the Interior, MMS and must be received by the invoice date.* To ensure proper credit to your account, please include your payment and the remittance copy of the bill for collection. In order to simplify the billing process, MMS has calculated and accumulated royalty underpayments into Federal Lease No. 029-003385-0. However, ARCO will still be required to submit separate lines on Form MMS-2014 for each lease and sales month. Your payment should be tendered in accordance with the regulations at 30 CFR § 218.51 (1996) and accompanied by an appropriately completed ***green*** Form MMS-2014 (forms and instructions enclosed) using adjustment reason code ***40***. The green Form MMS-2014 must reflect ***752179*** in block 3a "Payor-Assigned Document Number."

The State has identified a consistent and systemic error in the reporting and paying of royalties on the various leases located in the San Juan 30-6 Unit in the San Juan Basin. Therefore, ARCO is directed to perform the following:

1. For the period January 1989 through August 1996, recalculate the royalties for all other coalbed methane Federal and Indian leases in the San Juan Basin that have been transported and processed through the Val Verde System, and the price has been reduced for the costs of the transportation and removal of the CO_2 from the gas stream. Include in the calculation all non-operated Federal and Indian leases, where

ARCO takes their gas in-kind, and sells the gas arm's length to MOTI or any other purchaser.

2. If ARCO's royalty redetermination indicates additional royalties are due, all payments must be made within 90 days of receipt of this letter. Your payments and Form MMS-2014 must be completed in accordance with the instructions indicated above.

3. All supporting calculations and source documents are subject to audit by MMS, therefore, should be retained by ARCO until MMS completes its followup compliance testing.

Appropriate late payment charges pursuant to 30 CFR § 218.102 (1996) will be computed and billed to ARCO upon receipt of payment of the additional royalties due.

Royalty calculations subsequent to the current production month must also be in compliance with regulatory determination referred to in this order. If in the future, we determine that the required recomputations have not been performed and future royalty payments do not comply with this order, the violation may be considered willful.

A copy of your payment and green Form MMS-2014 should be sent to:

Mr. Jay Norman
New Mexico Taxation and Revenue Department
Oil and Gas Audit/Compliance Section
1200 South St. Francis Drive
Santa Fe, New Mexico 87502

Section 109 of FOGRMA, promulgated at 30 CFR § 241.51 (1996), authorizes MMS to assess civil penalties for failure or refusal to comply with the requirements of FOGRMA or any statute, regulation, rule, order, lease, or permit. Consequently, your failure to comply with the terms of this order may be considered a violation pursuant to 30 CFR § 241.51 and could subject you to penalties of up to $5,000

per violation for each day such violation continues and up to $10,000 per violation for each day if the violation is considered to be willful.

You have the right to appeal in accordance with the provisions of 30 CFR Part 290 (1996) and the Federal Oil and Gas Royalty Simplification and Fairness Act of 1996 (Public Law 104-185, 110 Statute 1700). Any appeal taken will be to the Director, MMS, and the notice of appeal must be filed within 30 days from the date of receipt of this order with:

Mr. James R. Detlefs, Chief
State and Indian Compliance Division
Minerals Management Service
P.O. Box 25165, Mail Stop 3660
Denver, Colorado 80225-0165

Any notice of appeal must be accompanied by a written statement of reasons, as you deem adequate, to justify removal or modification of this order. Within 60 days from receipt of this order, the appellant will be permitted to file additional statements of reasons or written briefs. However, you must state in your initial notice of appeal to MMS your intention to submit additional statements of reasons. Extensions for filing the statement of reasons will not be permitted unless requested in writing by the appellant within the 30-day period allowed for filing the appeal with justification showing good cause for the time extension.

In accordance with the provisions of 30 CFR § 243.2 (1996), compliance with this order will be suspended upon the posting of an adequate surety pending the outcome of the appeal. The surety must be received at MMS by the due date. The surety must be in the amount of $1,265,100 which includes the principal plus interest that will accrue through January 31, 1998. Upon request by MMS, the amount of the surety will be increased periodically, if necessary, to

cover any additional interest that may accrue. Enclosed are instructions for posting the surety.

If you have any questions, please contact Mr. Jay Norman of the New Mexico Taxation and Revenue Department at (505) 827-0986 or Ms. Carol Green of MMS at (303) 275-7459.

Sincerely,

//James R. Detlefs//
James R. Detlefs
Chief, State and Indian
Compliance Division

7 Enclosures

APPENDIX J

[Seal Omitted]

United States Department of the Interior

MINERALS MANAGEMENT SERVICE

Royalty Management Program
P.O. Box 25165
Denver, Colorado 80225-0165

April 22, 1996

Dear Operator/Payor:

The Minerals Management Service (MMS) has received many questions, primarily from producers in the vicinity of New Mexico's San Juan Basin, on how to report and pay royalties on coalbed methane. The following guidelines answer those questions.

These guidelines apply to coalbed methane produced from Federal and Indian leases. You must follow these guidelines to ensure proper payment of royalties and correct reporting of production. They apply specifically to circumstances where carbon dioxide (CO_2) is removed from produced coalbed methane and is vented without sale.

Valuing Production

Sales at the wellhead or CDP

If you sell your coalbed methane at the wellhead or a central delivery point (CDP) in the field or unit, you must value the coalbed methane as unprocessed gas under 30 CFR § 206.152 (1995).

For arm's-length sales, value for royalty purposes will be the gross proceeds you receive under your arm's length contract. However, that value cannot be reduced, either directly or indirectly, for the costs of placing coalbed methane in marketable condition. Placing production in marketable condition includes, but is not limited to, CO_2 removal (commonly called sweetening). Under 30 CFR § 206.152(I), if your sales price is reduced by fees for

services to place production in marketable condition, either directly or indirectly, you must add that portion of the fees attributable to those services, including CO_2 removal, to your gross proceeds received from the sale of the coalbed methane to determine value for royalty purposes. If you pay a bundled fee for both CO_2 removal and transportation, we recognize that you may be unable to obtain the information necessary to segregate the CO_2-removal costs. If you are in this situation, contact the MMS' Valuation and Standards Division at 303-275-7240 for assistance in determining the portion of your service fees attributable to CO_2 removal.

For non-arm's-length sales, you must determine the value of the coalbed methane under the methods (benchmarks) described at 30 CFR § 206.152(c). Again, you cannot deduct costs of placing the coalbed methane in marketable condition. You must ensure that any value determined under the methods is not improperly adjusted for nonallowable costs.

For Indian leases, you must also meet the dual accounting and majority price requirement established by regulation and lease terms. However, for both Federal and Indian leases, under no circumstances can the value of the production for royalty purposes be less than the gross proceeds accruing to the lessee, less applicable allowances.

Sales at the CO_2-removal facility

If you sell your coalbed methane at the tailgate of a CO_2-removal or other treating facility, you must value it as unprocessed gas under 30 CFR § 206.152. For arm's-length sales, value will be your gross proceeds under the arm's-length contract. For non-arm's-length sales, you must determine the value of the coalbed methane under the benchmarks at 30 CFR § 206.152(c). You cannot deduct costs of removing the CO_2 or otherwise placing the coalbed methane in marketable condition. However, you can deduct costs of transportation as discussed below.

Determining Allowable Deductions From value

Transportation allowances

You can take a transportation allowance for your reasonable, actual, and necessary costs of transporting the coalbed methane from the royalty measurement point (either the wellhead or the CDP) to the point of sale remote from the lease. You must use the regulation in 30 CFR § 206.156 and 206.157 (1995) and the instructions in Chapter 6 of the *Oil and Gas Payor Handbook, Volume III*, to calculate your transportation allowance.

In general, the regulations state that (1) you must allocate your transportation charges to all products produced and transported, and (2) you can only deduct the allocated costs from the value of products that are royalty bearing. For coalbed methane production, you can increase the transportation costs allocated to the methane component for the amount of CO_2 permitted in the main (inter- or intrastate) transmission line. For example, if your gas stream consists of 90 percent methane and 10 percent CO_2 and the main transmission line allows 2 percent CO_2 in the makeup of its gas stream, you can include the costs of transporting the 2 percent CO_2 volume (or 92 percent of the total transportation cost) when calculating your allowance for methane.

You can include costs of dehydration occurring after metering at the royalty measurement point in your transportation allowance but you cannot deduct costs of dehydration occurring at the wellhead. You can include costs for compression occurring downstream of the royalty measurement point, to the extent the compression is necessary for transportation. This includes compression at the CDP and in the transportation system to the CO_2-removal facility. You cannot include those compression costs associated with production operations.

You must convert any payment for transportation that is made in-kind for dehydration and allowable compression to

a dollar equivalent and include this amount in the transportation allowance deduction. You must allocate transportation costs for any allowable dehydration and compression (either in-value or in-kind) between the methane and CO_2 in the [s]ame manner as the in-value transportation cost.

You cannot include the costs of removing CO_2 as part of your transportation allowance. If you pay a bundled fee for both transportation and CO_2 removal and are unable to segregate the fee between these two [s]ervices, the MMS' Valuation and Standards Division will help you determine the proper portion attributable to transportation.

Processing allowances

You cannot take a [processing] allowance for your costs of removing CO_2.

Other deductions

You cannot include any costs associated with moving the production from the wellhead to the CDP (gathering) when the Bureau of Land Management (BLM) has approved the CDP as the royalty measurement point.

You cannot include any costs associated with wellhead separation.

Reporting Production

For each lease or agreement producing coalbed methane, you must report the total volume of gas measured at the BLM-approv[e]d royalty measurement point on the Monthly Report of Operations (Form MMS-3160) as a Gas Transfer. Report the four-digit gas plant number and name of the plant receiving the largest volume of gas from the property (if gas is being transferred to more than one plant) in the Plant Number/Name field. If you are using additional plants for CO_2 removal, identify the other plant(s) in the Comments section.

Report the Btu content of the gas, as determined at the royalty measurement point, on the API Gravity/Btu Content

line. Report the percentage of CO_2 in the gas stream, as measured at the royalty measurement point, in the Comments section.

If you report gas as Used on or for Benefit of Lease, you must be consistent with the approvals of BLM. Do not include any gas used off-lease for compression, dehydration, or CO_2 removal unless specifically approved by BLM.

Reporting Royalty

For each lease/revenue source combination, you must report the allocated share of the total volume of gas determined at the BLM-approved royalty measurement point in the Sales Quantity field on the Report of Sales and Royalty Remittance (Form MMS-2014). Report the gas as unprocessed gas (Product Code 04) using Transaction Code 01, Royalty Due. Report the Btu content of the gas, as determined at the royalty measurement point, in the Quality Measurement field.

Base the value reported in the Sales Value field on the criteria described in the Valuing Production section of this letter.

Report transportation allowances against Product Code 04 using Transaction Code 11.

If you have any questions about production or royalty reporting, contact the MMS Reports Branch at 800-525-0309 or 303-231-3288.

Sincerely,

/s/ Robert E. Brown

Robert E. Brown
Acting Associate Director for
Royalty Management

APPENDIX K

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

SEPTEMBER TERM, 2004
NO. 04-5006
CONSOLIDATED WITH 04-5007.

AMOCO PRODUCTION COMPANY,
APPELLANT

V.

REBECCA W. WATSON, ASSISTANT SECRETARY FOR LAND AND MINERAL MANAGEMENT, ET AL.,
APPELLEES

00CV01480, 00CV02933
FILED ON: AUGUST 24, 2005

Before: Edwards, Sentelle, and Roberts, Circuit Judges.

ORDER

Upon consideration of appellants' petition for rehearing filed July 25, 2005, it is **ORDERED** that the petition be denied.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY:
Michael C. McGrail
Deputy Clerk

APPENDIX L

RELEVANT STATUTORY AND REGULATORY PROVISIONS

1. Section 17 of the Mineral Leasing Act of 1920, codified as amended, 30 U.S.C. § 226, 41 Stat. 437, provides, in relevant part:

§226. Lease of oil and gas lands

(a) Authority of Secretary

All lands subject to disposition under this chapter which are known or believed to contain oil or gas deposits may be leased by the Secretary.

(b) Lands within known geologic structure of a producing oil or gas field; lands within special tar sand areas; competitive bidding; royalties

(1)(A) All lands to be leased which are not subject to leasing under paragraphs (2) and (3) of this subsection shall be leased as provided in this paragraph to the highest responsible qualified bidder by competitive bidding under general regulations in units of not more than 2,560 acres, except in Alaska, where units shall be not more than 5,760 acres. Such units shall be as nearly compact as possible. Lease sales shall be conducted by oral bidding. Lease sales shall be held for each State where eligible lands are available at least quarterly and more frequently if the Secretary of the Interior determines such sales are necessary. A lease shall be conditioned upon the payment of a royalty at a rate of not less than 12.5 percent in amount or value of the production removed or sold from the lease. The Secretary shall accept the highest bid from a responsible qualified bidder which is equal to or greater than the national minimum acceptable bid, without evaluation of the value of the lands proposed for lease. Leases shall be issued within 60 days following payment by the successful bidder of the remainder of the bonus bid, if any, and the annual rental for the first lease year. All bids for less than

the national minimum acceptable bid shall be rejected. Lands for which no bids are received or for which the highest bid is less than the national minimum acceptable bid shall be offered promptly within 30 days for leasing under subsection (c) of this section and shall remain available for leasing for a period of 2 years after the competitive lease sale.

(B) The national minimum acceptable bid shall be $2 per acre for a period of 2 years from December 22, 1987. Thereafter, the Secretary, subject to paragraph (2)(B), may establish by regulation a higher national minimum acceptable bid for all leases based upon a finding that such action is necessary: (i) to enhance financial returns to the United States; and (ii) to promote more efficient management of oil and gas resources on Federal lands. Ninety days before the Secretary makes any change in the national minimum acceptable bid, the Secretary shall notify the Committee on Natural Resources of the United States House of Representatives and the Committee on Energy and Natural Resources of the United States Senate. The proposal or promulgation of any regulation to establish a national minimum acceptable bid shall not be considered a major Federal action subject to the requirements of section 4332(2)(C) of Title 42.

(2)(A)(i) If the lands to be leased are within a special tar sand area, they shall be leased to the highest responsible qualified bidder by competitive bidding under general regulations in units of not more than 5,760 acres, which shall be as nearly compact as possible, upon the payment by the lessee of such bonus as may be accepted by the Secretary.

(ii) Royalty shall be 12 1/2 per centum in amount or value of production removed or sold from the lease, subject to subsection (k)(1)(c) of this section.

(iii) The Secretary may lease such additional lands in special tar sand areas as may be required in support

of any operations necessary for the recovery of tar sands.

(iv) No lease issued under this paragraph shall be included in any chargeability limitation associated with oil and gas leases.

(B) For any area that contains any combination of tar sand and oil or gas (or both), the Secretary may issue under this chapter, separately—

(i) a lease for exploration for and extraction of tar sand; and

(ii) a lease for exploration for and development of oil and gas.

(C) A lease issued for tar sand shall be issued using the same bidding process, annual rental, and posting period as a lease issued for oil and gas, except that the minimum acceptable bid required for a lease issued for tar sand shall be $2 per acre.

2. Section 2 of the Act of July 18, 1966, codified as amended at 28 U.S.C. § 2415, 80 Stat. 304, provides, in relevant part:

§ 2415. Time for commencing actions brought by the United States

(a) Subject to the provisions of section 2416 of this title, and except as otherwise provided by Congress, every action for money damages brought by the United States or an officer or agency thereof which is founded upon any contract express or implied in law or fact, shall be barred unless the complaint is filed within six years after the right of action accrues or within one year after final decisions have been rendered in applicable administrative proceedings required by contract or by law, whichever is later: *Provided*, That in the event of later partial payment or written acknowledgment of debt, the right of action shall be deemed to accrue again at the time of each such payment or acknowledgment: *Provided further*, That an action for money damages brought by the United States for or on behalf of a recognized tribe, band or group of American Indians shall not be barred unless the complaint is filed more than six years and ninety days after the right of action accrued: *Provided further*, That an action for money damages which accrued on the date of enactment of this Act in accordance with subsection (g) brought by the United States for or on behalf of a recognized tribe, band, or group of American Indians, or on behalf of an individual Indian whose land is held in trust or restricted status, shall not be barred unless the complaint is filed sixty days after the date of publication of the list required by section 4(c) of the Indian Claims Limitation Act of 1982: *Provided*, That, for those claims that are on either of the two lists published pursuant to the Indian Claims Limitation Act of 1982, any right of action shall be barred unless the complaint is filed within (1) one year after the Secretary of the Interior has published in the Federal Register a notice rejecting such

claim or (2) three years after the date the Secretary of the Interior has submitted legislation or legislative report to Congress to resolve such claim or more than two years after a final decision has been rendered in applicable administrative proceedings required by contract or by law, whichever is later.

(b) Subject to the provisions of section 2416 of this title, and except as otherwise provided by Congress, every action for money damages brought by the United States or an officer or agency thereof which is founded upon a tort shall be barred unless the complaint is filed within three years after the right of action first accrues: *Provided*, That an action to recover damages resulting from a trespass on lands of the United States; an action to recover damages resulting from fire to such lands; an action to recover for diversion of money paid under a grant program; and an action for conversion of property of the United States may be brought within six years after the right of action accrues, except that such actions for or on behalf of a recognized tribe, band or group of American Indians, including actions relating to allotted trust or restricted Indian lands, may be brought within six years and ninety days after the right of action accrues, except that such actions for or on behalf of a recognized tribe, band, or group of American Indians, including actions relating to allotted trust or restricted Indian lands, or on behalf of an individual Indian whose land is held in trust or restricted status which accrued on the date of enactment of this Act in accordance with subsection (g) may be brought on or before sixty days after the date of the publication of the list required by section 4(c) of the Indian Claims Limitation Act of 1982: *Provided*, That, for those claims that are on either of the two lists published pursuant to the Indian Claims Limitation Act of 1982, any right of action shall be barred unless the complaint is filed within (1) one year after the Secretary of the Interior has published in the Federal Register a notice rejecting such claim or (2)

three years after the Secretary of the Interior has submitted legislation or legislative report to Congress to resolve such claim.

(c) Nothing herein shall be deemed to limit the time for bringing an action to establish the title to, or right of possession of, real or personal property.

(d) Subject to the provisions of section 2416 of this title and except as otherwise provided by Congress, every action for the recovery of money erroneously paid to or on behalf of any civilian employee of any agency of the United States or to or on behalf of any member or dependent of any member of the uniformed services of the United States, incident to the employment or services of such employee or member, shall be barred unless the complaint is filed within six years after the right of action accrues: *Provided*, That in the event of later partial payment or written acknowledgment of debt, the right of action shall be deemed to accrue again at the time of each such payment or acknowledgment.

(e) In the event that any action to which this section applies is timely brought and is thereafter dismissed without prejudice, the action may be recommenced within one year after such dismissal, regardless of whether the action would otherwise then be barred by this section. In any action so recommenced the defendant shall not be barred from interposing any claim which would not have been barred in the original action.

(f) The provisions of this section shall not prevent the assertion, in an action against the United States or an officer or agency thereof, of any claim of the United States or an officer or agency thereof against an opposing party, a co-party, or a third party that arises out of the transaction or occurrence that is the subject matter of the opposing party's claim. A claim of the United States or an officer or agency thereof that does not arise out of the transaction or

occurrence that is the subject matter of the opposing party's claim may, if time-barred, be asserted only by way of offset any may be allowed in an amount not to exceed the amount of the opposing party's recovery.

(g) Any right of action subject to the provisions of this section which accrued prior to the date of enactment of this Act shall, for purposes of this section, be deemed to have accrued on the date of enactment of this Act.

(h) Nothing in this Act shall apply to actions brought under the Internal Revenue Code or incidental to the collection of taxes imposed by the United States.

(i) The provisions of this section shall not prevent the United States or an officer or agency thereof from collecting any claim of the United States by means of administrative offset, in accordance with section 3716 of title 31.

3. Section 206 of Title 30 of the Code of Federal Regulations provides, in relevant part:

§ 206.151 Definitions.

For purposes of this subpart:

"*Allowance*" means an approved or an MMS-initially accepted deduction in determining value for royalty purposes. "Processing allowance" means an allowance for the reasonable, actual costs incurred by the lessee for processing gas, or an approved or MMS-initially accepted deduction for costs of such processing, determined pursuant to this subpart. "Transportation allowance" means an allowance for the reasonable, actual costs incurred by the lessee for moving unprocessed gas, residue gas, or gas plant products to a point of sale or point of delivery off the lease, unit area, communitized area, or away from a processing plant, excluding gathering, or an approved or MMS-initially accepted deduction for costs of such transportation, determined pursuant to this subpart.

"*Area*" means a geographic region at least as large as the defined limits of an oil and/or gas field, in which oil and/or gas lease products have similar quality, economic, and legal characteristics.

"*Arm's length contract*" means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership:

(a) Ownership in excess of 50 percent constitutes control;

(b) Ownership of 10 through 50 percent creates a presumption of control; and

(c) Ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates.

Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. The MMS may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month as well as when the contract was executed.

"Audit" means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Federal and Indian leases.

"BIA" means the Bureau of Indian Affairs of the Department of the Interior.

"BLM" means the Bureau of Land Management of the Department of the Interior.

"Compression" means the process of raising the pressure of gas.

"Condensate" means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without resorting to processing. Condensate is the mixture of liquid hydrocarbons that results from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

"Contract" means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

"Field" means a geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumu-

lations known to be within those reservoirs vertically projected to the land surface. Onshore fields are usually given names and their official boundaries are often designated by oil and gas regulatory agencies in the respective States in which the fields are located. Outer Continental Shelf (OCS) fields are named and their boundaries are designated by MMS.

"Gas" means any fluid, either combustible or noncombustible, hydrocarbon or nonhydrocarbon, which is extracted from a reservoir and which has neither independent shape nor volume, but tends to expand indefinitely. It is a substance that exists in a gaseous or rarefied state under standard temperature and pressure conditions.

"Gas plant products" means separate marketable elements, compounds, or mixtures, whether in liquid, gaseous, or solid form, resulting from processing gas, excluding residue gas.

"Gathering" means the movement of lease production to a central accumulation and/or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or MMS OCS operations personnel for onshore and OCS leases, respectively.

"Gross proceeds" (for royalty payment purposes) means the total monies and other consideration accruing to an oil and gas lessee for the disposition of unprocessed gas, residue gas, or gas plant products. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as compression, dehydration, measurement, and/or field gathering to the extent that the lessee is obligated to perform them at no cost to the Federal Government or Indian lessor, and payments for gas processing rights. Gross proceeds, as applied to gas, also includes but is not limited to: Take-or-pay payments; reimbursements for severance taxes; and other reimbursements. Tax reim-

bursements are part of the gross proceeds accruing to a lessee even though the Federal or Indian royalty interest may be exempt from taxation. Payments or credits for advanced exploration or development costs or prepaid reserve payments that are subject to recoupment through credits against the purchase price or through reduced prices in later sales and which are made before production commences become part of gross proceeds as of the time of first production. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

"Indian allottee" means any Indian for whom land or an interest in land is held in trust by the United States or who holds title subject to Federal restriction against alienation.

"Indian Tribe" means any Indian Tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any land or interest in land is held in trust by the United States or which is subject to Federal restriction against alienation.

"Lease" means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of lease products—or the land area covered by that authorization, whichever is required by the context.

"Lease products" means any leased minerals attributable to, originating from, or allocated to Outer Continental Shelf or onshore Federal or Indian leases.

"Lessee" means any person to whom the United States, an Indian Tribe, or an Indian allottee issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator

or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

"Like-quality lease products" means lease products which have similar chemical, physical, and legal characteristics.

"Marketable condition" means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area.

"Marketing affiliate" means an affiliate of the lessee whose function is to acquire only the lessee's production and to market that production.

"Minimum royalty" means that minimum amount of annual royalty that the lessee must pay as specified in the lease or in applicable leasing regulations.

"Net-back method" (or work-back method) means a method for calculating market value of gas at the lease. Under this method, costs of transportation, processing, or manufacturing are deducted from the proceeds received for the gas, residue gas or gas plant products, and any extracted, processed, or manufactured products, or from the value of the gas, residue gas or gas plant products, and any extracted, processed, or manufactured products, at the first point at which reasonable values for any such products may be determined by a sale pursuant to an arm's-length contract or comparison to other sales of such products, to ascertain value at the lease.

"Net output" means the quantity of residue gas and each gas plant product that a processing plant produces.

"Net profit share" (for applicable Federal and Indian leases) means the specified share of the net profit from production of oil and gas as provided in the agreement.

"Outer Continental Shelf (OCS)" means all submerged lands lying seaward and outside of the area of land beneath navigable waters as defined in section 2 of the Submerged

Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

"Person" means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

"Posted price" means the price, net of all adjustments for quality and location, specified in publicly available price bulletins or other price notices available as part of normal business operations for quantities of unprocessed gas, residue gas, or gas plant products in marketable condition.

"Processing" means any process designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes which normally take place on or near the lease, such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, and compression, are not considered processing. The changing of pressures and/or temperatures in a reservoir is not considered processing.

"Residue gas" means that hydrocarbon gas consisting principally of methane resulting from processing gas.

"Section 6 lease" means an OCS lease subject to section 6 of the Outer Continental Shelf Lands Act, as amended, 43 U.S.C. 1335.

"Selling arrangement" means the individual contractual arrangements under which sales or dispositions of gas, residue gas and gas plant products are made. Selling arrangements are described by illustration in the MMS Royalty Management Program Oil and Gas Payor Handbook.

"Spot sales agreement" means a contract wherein a seller agrees to sell to a buyer a specified amount of unprocessed gas, residue gas, or gas plant products at a specified price over a fixed period, usually of short duration, which does not normally require a cancellation notice to ter-

minate, and which does not contain an obligation, nor imply an intent, to continue in subsequent periods.

"Warranty contract" means a long-term contract entered into prior to 1970, including any amendments thereto, for the sale of gas wherein the producer agrees to sell a specific amount of gas and the gas delivered in satisfaction of this obligation may come from fields or sources outside of the designated fields.

§ 206.152 Valuation standards–unprocessed gas.

(a)(1) This section applies to the valuation of all gas that is not processed and all gas that is processed but is sold or otherwise disposed of by the lessee pursuant to an arm's-length contract prior to processing. Where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right, or where the lessee's contract for the sale of gas prior to processing provides for the value to be determined based upon a percentage of the purchaser's proceeds resulting from processing the gas, § 206.153 shall apply instead of this section. This section also applies to processed gas which must be valued prior to processing in accordance with § 206.155.

(2) The value of production, for royalty purposes, of gas subject to this subpart shall be the value of gas determined pursuant to this section less applicable allowances determined pursuant to this subpart.

(3)(i) For any Indian leases which provide that the Secretary may consider the highest price paid or offered for a major portion of production (major portion) in determining value of production for royalty purposes, if data are available to compute a major portion MMS will, where practicable, compare the value determined in accordance with this section with the major portion. The value to be used in determining the value of production for royalty purposes shall be the higher of those two values.

(ii) For purposes of this paragraph, major portion means the highest price paid or offered at the time of production for the major portion of gas production from the same field. The major portion will be calculated using like-quality gas sold under arm's-length contracts from the same field (or, if necessary to obtain a reasonable sample, from the same area) for each month. All such sales will be arrayed from highest price to lowest price (at the bottom). The major portion is that price at which 50 percent (by volume) plus 1 mcf of the gas (starting from the bottom) is sold.

(b)(1)(i) The value of gas which is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1) (ii) and (iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit. For purposes of this section, gas which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the gas. If the contract does not reflect the total consideration, then the MMS may require that the gas sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If the MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the

lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the gas production be valued pursuant to paragraphs (c)(2) or (c)(3) of this section, and in accordance with the notification requirements of paragraph (e) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of gas sold pursuant to a warranty contract shall be determined by MMS, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by MMS.

(3) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the gas.

(c) The value of gas subject to this section which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like-quality gas in the same field (or, if necessary to obtain a reasonable sample, from the same area). In evaluating the comparability of arm's-length con-

tracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of gas, volume, and such other factors as may be appropriate to reflect the value of the gas;

(2) A value determined by consideration of other information relevant in valuing like-quality gas, including gross proceeds under arm's-length contracts for like-quality gas in the same field or nearby fields or areas, posted prices for gas, prices received in arm's-length spot sales of gas, other reliable public sources of price or market information, and other information as to the particular lease operation or the saleability of the gas; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which gas may be sold is less than the value determined pursuant to this section, then MMS shall accept such maximum price as the value. For purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed in paragraph (d)(1) of this section shall not apply to gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal or Indian lessee will make available upon request to the authorized MMS, State, or Indian representatives, to the Office of the Inspector General of the Department of the Interior, or other person authorized to receive such information, arm's-length sales and volume data for like-quality production sold, purchased or otherwise obtained by the lessee from the field or area or from nearby fields or areas.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraph (c)(2) or (c)(3) of this section. The notification shall be by letter to the MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS-2014 using a valuation method authorized by paragraph (c)(2) or (c)(3) of this section, and each time there is a change in a method under paragraph (c)(2) or (c)(3) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest on that difference computed pursuant to 30 C.F.R. 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional

information MMS deems necessary. In making a value determination MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for lease production, less applicable allowances determined pursuant to this subpart.

(i) The lessee is required to place gas in marketable condition at no cost to the Federal Government or Indian lessor unless otherwise provided in the lease agreement. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. If there is no contract revision or amendment, and the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be con-

strued to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of gas.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by the MMS of value under this section shall be considered final or binding as against the Federal Government, its beneficiaries, the Indian Tribes, or allottees until the audit period is formally closed.

(l) Certain information submitted to MMS to support valuation proposals, including transportation or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal Law. Any data specified by law to be privileged, confidential, or otherwise exempt will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this subpart are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 C.F.R. Part 2. Nothing in this section is intended to limit or diminish in any manner whatsoever the right of an Indian lessor to obtain any and all information as such lessor may be lawfully entitled from MMS or such lessor's lessee directly under the terms of the lease, 30 U.S.C. 1733, or other applicable law.

§ 206.153 Valuation standards–processed gas.

(a)(1) This section applies to the valuation of all gas that is processed by the lessee and any other gas production to which this subpart applies and that is not subject to the valuation provisions of § 206.152 of this subpart. This section applies where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right, or where the lessee's contract for the sale of gas prior to processing provides for the value to be deter-

mined based upon a percentage of the purchaser's proceeds resulting from processing the gas (in which event these regulations will apply to determine value as if the person actually selling or disposing of the residue gas or gas plant products were the lessee of the Federal or Indian lease).

(2) The value of production, for royalty purposes, of gas subject to this section shall be the combined value of the residue gas and all gas plant products determined pursuant to this section, plus the value of any condensate recovered downstream of the point of royalty settlement without resorting to processing determined pursuant to § 206.102 of this part, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

(3)(i) For any Indian leases which provide that the Secretary may consider the highest price paid or offered for a major portion of production (major portion) in determining value for royalty purposes, if data are available to compute a major portion MMS will, where practicable, compare the values determined in accordance with this section for any lease product with the major portion determined for that lease product. The value to be used in determining the value of production for royalty purposes shall be the higher of those two values.

(ii) For purposes of this paragraph, major portion means the highest price paid or offered at the time of production for the major portion of gas production from the same field, or for residue gas or gas plant products from the same processing plant, as applicable. The major portion will be calculated using like-quality lease products sold under arm's-length contracts from the same field or processing plant (or, if necessary to obtain a reasonable sample, from the same area or nearby processing plants) for each month. All such sales will be arrayed from highest price to lowest price (at the bottom). The major portion is that price at which 50 percent (by volume) plus 1 mcf of the gas (starting

from the bottom) is sold, or for gas plant products, 50 percent (by volume) plus 1 unit.

(b)(1)(i) The value of the residue gas or any gas plant product which is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1) (ii) and (iii) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value that the lessee reports for royalty purposes is subject to monitoring, review, and audit. For purposes of this section, residue gas or any gas plant product which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate.

(ii) In conducting these reviews and audits, MMS will examine whether or not the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the residue gas or gas plant product. If the contract does not reflect the total consideration, then the MMS may require that the residue gas or gas plant product sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If the MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the residue gas or gas plant product because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the residue gas or gas plant product be valued pursuant to paragraphs (c)(2) or (c)(3) of this section, and in accordance with the notification requirements of paragraph (e) of this section. When MMS determines that

the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of residue gas sold pursuant to a warranty contract shall be determined by MMS, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by MMS.

(3) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the residue gas or gas plant product.

(c) The value of residue gas or any gas plant product which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like quality residue gas or gas plant products from the same processing plant (or, if necessary to obtain a reasonable sample, from nearby plants). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of residue gas or gas plant products, volume,

and such other factors as may be appropriate to reflect the value of the residue gas or gas plant products;

(2) A value determined by consideration of other information relevant in valuing like-quality residue gas or gas plant products, including gross proceeds under arm's-length contracts for like-quality residue gas or gas plant products from the same gas plant or other nearby processing plants, posted prices for residue gas or gas plant products, prices received in spot sales of residue gas or gas plant products, other reliable public sources of price or market information, and other information as to the particular lease operation or the saleability of such residue gas or gas plant products; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which any residue gas or gas plant products may be sold is less than the value determined pursuant to this section, then MMS shall accept such maximum price as the value. For the purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed by paragraph (d)(1) of this section shall not apply to residue gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines upon review or audit that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal or Indian lessee will make available upon request to the authorized MMS, State, or Indian representatives, to the Office of the Inspector General of the Department of the Interior, or other persons authorized to receive such information, arm's-length sales and volume data for like-quality residue gas and gas plant products sold, purchased or otherwise obtained by the lessee from the same processing plant or from nearby processing plants.

(3) A lessee shall notify MMS if it has determined any value pursuant to paragraph (c)(2) or (c)(3) of this section. The notification shall be by letter to the MMS Associate Director for Royalty Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS-2014 using a valuation method authorized by paragraph (c)(2) or (c)(3) of this section, and each time there is a change in a method under paragraph (c)(2) or (c)(3) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest computed on that difference pursuant to 30 C.F.R. 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional

information MMS deems necessary. In making a value determination, MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for residue gas and/or any gas plant products, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

(i) The lessee is required to place residue gas and gas plant products in marketable condition at no cost to the Federal Government or Indian lessor unless otherwise provided in the lease agreement. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting

from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of residue gas or gas plant product.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding against the Federal Government, its beneficiaries, the Indian Tribes, or allottees, until the audit period is formally closed.

(l) Certain information submitted to MMS to support valuation proposals, including transportation allowances, processing allowances or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt, will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this Part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 C.F.R. Part 2. Nothing in this section is intended to limit or diminish in any manner whatsoever the right of an Indian lessor to obtain any and all information as such lessor may be lawfully entitled from the MMS or such lessor's lessee directly under the terms of the lease, 30 U.S.C. 1733, or other applicable law.

§ 206.154 Determination of quantities and qualities for computing royalties.

(a)(1) Royalties shall be computed on the basis of the quantity and quality of unprocessed gas at the point of royalty settlement approved by BLM or MMS for onshore and OCS leases, respectively.

(2) If the value of gas determined pursuant to § 206.152 of this subpart is based upon a quantity and/or quality that is different from the quantity and/or quality at the point of royalty settlement, as approved by BLM or MMS, that value shall be adjusted for the differences in quantity and/or quality.

(b)(1) For residue gas and gas plant products, the quantity basis for computing royalties due is the monthly net output of the plant even though residue gas and/or gas plant products may be in temporary storage.

(2) If the value of residue gas and/or gas plant products determined pursuant to § 206.153 of this subpart is based upon a quantity and/or quality of residue gas and/or gas plant products that is different from that which is attributable to a lease, determined in accordance with paragraph (c) of this section, that value shall be adjusted for the differences i quantity and/or quality.

(c) The quantity of the residue gas and gas plant products attributable to a lease shall be determined according to the following procedure:

(1) When the net output of the processing plant is derived from gas obtained from only one lease, the quantity of the residue gas and gas plant products on which computations of royalty are based is the net output of the plant.

(2) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of uniform content, the quantity of the residue gas and gas plant products allocable to each lease shall be in the same proportions as the ratios obtained by dividing the amount of gas delivered to the plant from each lease by the total amount of gas delivered from all leases.

(3) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of nonuniform content, the quantity of the residue gas allocable to each lease will be determined by multiplying the

amount of gas delivered to the plant from the lease by the residue gas content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant, and then multiplying the net output of the residue gas by the arithmetic quotient obtained. The net output of gas plant products allocable to each lease will be determined by multiplying the amount of gas delivered to the plant from the lease by the gas plant product content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant, and then multiplying the net output of each gas plant product by the arithmetic quotient obtained.

(4) A lessee may request MMS approval of other methods for determining the quantity of residue gas and gas plant products allocable to each lease. If approved, such method will be applicable to all gas production from Federal and Indian leases that is processed in the same plant.

(d)(1) No deductions may be made from the royalty volume or royalty value for actual or theoretical losses. Any actual loss of unprocessed gas that may be sustained prior to the royalty settlement metering or measurement point will not be subject to royalty provided that such loss is determined to have been unavoidable by BLM or MMS, as appropriate.

(2) Except as provided in paragraph (d)(1) of this section and 30 C.F.R. 202.151(c), royalties are due on 100 percent of the volume determined in accordance with paragraphs (a) through (c) of this section. There can be no reduction in that determined volume for actual losses after the quantity basis has been determined or for theoretical losses that are claimed to have taken place. Royalties are due on 100 percent of the value of the unprocessed gas, residue gas, and/or

gas plant products as provided in this subpart, less applicable allowances. There can be no deduction from the value of the unprocessed gas, residue gas, and/or gas plant products to compensate for actual losses after the quantity basis has been determined, or for theoretical losses that are claimed to have taken place.

§ 206.155 Accounting for comparison.

(a) Except as provided in paragraph (b) of this section, where the lessee (or a person to whom the lessee has transferred gas pursuant to a non-arm's-length contract or without a contract) processes the lessee's gas and after processing the gas the residue gas is not sold pursuant to an arm's-length contract, the value, for royalty purposes, shall be the greater of (1) the combined value, for royalty purposes, of the residue gas and gas plant products resulting from processing the gas determined pursuant to § 206.153 of this subpart, plus the value, for royalty purposes, of any condensate recovered downstream of the point of royalty settlement without resorting to processing determined pursuant to § 206.102 of this subpart; or (2) the value, for royalty purposes, of the gas prior to processing determined in accordance with § 206.152 of this subpart.

(b) The requirement for accounting for comparison contained in the terms of leases, particularly Indian leases, will govern as provided in § 206.150(b) of this subpart. When accounting for comparison is required by the lease terms, such accounting for comparison shall be determined in accordance with paragraph (a) of this section.

§ 206.156 Transportation allowances–general.

(a) Where the value of gas has been determined pursuant to § 206.152 or § 206.153 of this subpart at a point (e.g., sales point or point of value determination) off the lease, MMS shall allow a deduction for the reasonable actual costs incurred by the lessee to transport unprocessed gas, residue gas, and gas plant products from a lease to a

point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant.

(b) Transportation costs must be allocated among all products produced and transported as provided in § 206.157.

(c)(1) Except as provided in paragraph (c)(3) of this section, for unprocessed gas valued in accordance with § 206.152 of this subpart, the transportation allowance deduction on the basis of a selling arrangement shall not exceed 50 percent of the value of the unprocessed gas determined in accordance with § 206.152 of this subpart.

(2) Except as provided in paragraph (c)(3) of this section, for gas production valued in accordance with § 206.153 of this subpart the transportation allowance deduction on the basis of a selling arrangement shall not exceed 50 percent of the value of the residue gas or gas plant product determined in accordance with § 206.153 of this subpart. For purposes of this section, natural gas liquids shall be considered one product.

(3) Upon request of a lessee, MMS may approve a transportation allowance deduction in excess of the limitations prescribed by paragraphs (c)(1) and (2) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitations prescribed in paragraphs (c)(1) and (2) of this section were reasonable, actual, and necessary. An application for exception shall contain all relevant and supporting documentation necessary for the MMS to make a determination. Under no circumstances shall the value for royalty purposes under any selling arrangement be reduced to zero.

(d) If, after a review and/or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this subpart, then the lessee shall pay any additional royalties, plus interest, determined in accor-

dance with 30 C.F.R. 218.54, or shall be entitled to a credit, without interest.

§ 206.157 Determination of transportation allowances.

(a) *Arm's-length transportation contracts.* (1)(i) For transportation costs incurred by a lessee pursuant to an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the unprocessed gas, residue gas and/or gas plant products under that contract, except as provided in paragraphs (a)(1)(ii) and (iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. Such allowances shall be subject to the provisions of paragraph (f) of this section. Before any deduction may be taken, the lessee must submit a completed page one of Form MMS-4295 (and Schedule 1), Gas Transportation Allowance Report, in accordance with paragraph (c)(1) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS-4295 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee.

(ii) In conducting reviews and audits, MMS will examine whether or not the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration, then the MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(iii) If the MMS determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual

benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(2)(i) If an arm's-length transportation contract includes more than one product in a gaseous phase and the transportation costs attributable to each product cannot be determined from the contract, the total transportation costs shall be allocated in a consistent and equitable manner to each of the products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, no allowance may be taken for the costs of transporting lease production which is not royalty bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(3) If an arm's-length transportation contract includes both gaseous and liquid products and the transportation costs attributable to each cannot be determined from the contract, the lessee shall propose an allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. The initial proposal must be submitted by June 30, 1988, or within 3 months after the last day of the month for which the lessee requests a transportation allowance, whichever is later (unless MMS

approves a longer period). The MMS shall then determine the gas transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary.

(4) Where the lessee's payments for transportation under an arm's-length contract are not based on a dollar per unit, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(5) Where an arm's-length sales contract price or a posted price includes a provision whereby the listed price is reduced by a transportation factor, MMS will not consider the transportation factor to be a transportation allowance. The transportation factor may be used in determining the lessee's gross proceeds for the sale of the product. The transportation factor may not exceed 50 percent of the base price of the product without MMS approval.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs as provided in this paragraph. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and adjustment. Before any estimated or actual deduction may be taken, the lessee must submit a completed Form MMS-4295 in accordance with paragraph (c)(2) of this section. A transportation allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS-4295 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee. The MMS will monitor the allowance deductions to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may

direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial depreciable investment in the transportation system multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of the MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The MMS shall allow as a cost an amount equal to the allowable initial capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average rate as published in *Standard and Poor's Bond Guide* for the first month of the reporting period for which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent transportation allowance reporting period (which is determined pursuant to paragraph (c) of this section).

(3)(i) The deduction for transportation costs shall be determined on the basis of the lessee's cost of transporting each product through each individual transportation system. Where more than one product in a gaseous phase is transported, the allocation of costs to each of the products transported shall be made in a consistent and equitable manner in the same proportion as the ratio of the volume of each product (excluding waste products which have no

value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, the lessee may not take an allowance for transporting a product which is not royalty bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to the MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(4) Where both gaseous and liquid products are transported through the same transportation system, the lessee shall propose a cost allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. The initial proposal must be submitted by June 30, 1988 or within 3 months after the last day of the month for which the lessee begins the transportation, whichever is later, unless MMS approves a longer period. The MMS shall then determine the transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary.

(5) A lessee may apply to the MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(4) of this section. The MMS will grant the exception only if the lessee has a tariff for the transportation system approved by the Federal Energy Regulatory Commission (FERC) (for both Federal and Indian leases) or a state regulatory agency (for Federal leases). The MMS shall deny the exception request if it determines that: (i) The tariff is excessive as compared to arm's-length transportation charges by the lessee or others providing similar transportation services; or (ii) if

there are no arm's-length transportation charges by the lessee or others providing similar transportation services, the tariff significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements—(1) Arm's-length contracts.* (i) With the exception of those transportation allowances specified in paragraphs (c)(1)(v) and (vi) of this section, the lessee shall submit page one of the initial Form MMS-4295 (and Schedule 1) prior to, or at the same time as, the transportation allowance determined pursuant to an arm's-length contract is reported on Form MMS-2014, Report of Sales and Royalty Remittance. A Form MMS-4295 received by the end of the month that the Form MMS-2014 is due shall be considered to be timely received.

(ii) The initial Form MMS-4295 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page one of Form MMS-4295 (and Schedule 1) within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) The MMS may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(v) Transportation allowances which are based on arm's-length contracts and which are in effect at the time these

regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) The MMS may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(2) *Non-arm's-length or no contract.* (i) With the exception of those transportation allowances specified in paragraphs (c)(2)(v), (c)(2)(vii), and (c)(2)(viii) of this section, the lessee shall submit an initial Form MMS-4295 prior to, or at the same time as, the transportation allowance determined pursuant to a non-arm's-length contract or no-contract situation is reported on Form MMS-2014, Report of Sales and Royalty Remittance. A Form MMS-4295 received by the end of the month that the Form MMS-2014 is due shall be considered to be timely received. The initial report may be based upon estimated costs.

(ii) The initial Form MMS-4295 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the transportation under the non-arm's-length contract or the no contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed Form MMS-4295 containing the actual costs for the previous reporting period. If the transportation is continuing, the lessee shall include on Form MMS-4295 its estimated costs for the next calendar year. The estimated transportation allowance shall be based on the actual costs for the previous reporting period plus or minus any adjustments which are based on the lessee's knowledge of decreases or increases which will affect the allowance. Form

MMS-4295 must be received by MMS within 3 months after the end of the previous reporting period, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new transportation facilities or arrangements, the lessee's initial Form MMS-4295 shall include estimates of the allowable transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system, or if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(v) Non-arm's-length contract or no contract based transportation allowances which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by MMS, the lessee shall submit all data used to prepare its Form MMS-4295. The data shall be provided within a reasonable period of time, as determined by MMS.

(vii) The MMS may establish in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(viii) If the lessee is authorized to use its FERC-approved tariff as its transportation cost in accordance with subsection (b)(5) of this section, it shall follow the reporting requirements of subsection (c)(1) of this section.

(3) The MMS may establish reporting dates for individual lessees different than those specified in this subpart in order to provide more effective administration.

Lessees will be notified of any change in their reporting period.

(4) Transportation allowances must be reported as a separate line item on Form MMS-2014, unless MMS approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and failure to report.* (1) If a lessee deducts a transportation allowance on its Form MMS-2014 without complying with the requirements of this section, the lessee shall pay interest only on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 C.F.R. 218.54.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has estimated and taken during the reporting period, the lessee shall be required to pay additional royalties due, plus interest computed pursuant to 30 C.F.R. 218.54, retroactive to the first month the lessee is authorized to deduct a transportation allowance. If the actual transportation allowance is greater than the amount the lessee has estimated and taken during the reporting period, the lessee shall be entitled to a credit without interest.

(2) For lessees transporting production from onshore Federal and Indian leases, the lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(3) For lessees transporting gas production from leases on the OCS, if the lessee's estimated transportation allow-

ance exceeds the allowance based on actual costs, the lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with its payment, in accordance with instructions provided by MMS. If the lessee's estimated transportation allowance is less than the allowance based on actual costs, the refund procedure will be specified by MMS.

(f) *Actual or theoretical losses.* Notwithstanding any other provisions of this subpart, for other than arm's-length contracts no cost shall be allowed for transportation which results from payments (either volumetric or for value) for actual or theoretical losses. This section does not apply when the transportation allowance is based upon a FERC or state regulatory agency approved tariff.

(g) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of transportation costs.

§ 206.158 Processing allowances–general.

(a) Where the value of gas is determined pursuant to § 206.153 of this subpart, a deduction shall be allowed for the reasonable actual costs of processing.

(b) Processing costs must be allocated among the gas plant products. A separate processing allowance must be determined for each gas plant product and processing plant relationship. Natural gas liquids (NGL's) shall be considered as one product.

(c)(1) Except as provided in paragraph (d)(2) of this section, the processing allowance shall not be applied against the value of the residue gas. Where there is no residue gas MMS may designate an appropriate gas plant product against which no allowance may be applied.

(2) Except as provided in paragraph (c)(3) of this section, the processing allowance deduction on the basis of an

individual product shall not exceed 664 2/3 percent of the value of each gas plant product determined in accordance with § 206.153 of this subpart (such value to be reduced first for any transportation allowances related to postprocessing transportation authorized by § 206.156 of this subpart).

(3) Upon request of a lessee, MMS may approve a processing allowance in excess of the limitation prescribed by paragraph (c)(2) of this section. The lessee must demonstrate that the processing costs incurred in excess of the limitation prescribed in paragraph (c)(2) of this section were reasonable, actual, and necessary. An application for exception shall contain all relevant and supporting documentation for MMS to make a determination. Under no circumstances shall the value for royalty purposes of any gas plant product be reduced to zero.

(d)(1) Except as provided in paragraph (d)(2) of this section, no processing cost deduction shall be allowed for the costs of placing lease products in marketable condition, including dehydration, separation, compression, or storage, even if those functions are performed off the lease or at a processing plant. Where gas is processed for the removal of acid gases, commonly referred to as "sweetening," no processing cost deduction shall be allowed for such costs unless the acid gases removed are further processed into a gas plant product. In such event, the lessee shall be eligible for a processing allowance as determined in accordance with this subpart. However, MMS will not grant any processing allowance for processing lease production which is not royalty bearing.

(2)(i) If the lessee incurs extraordinary costs for processing gas production from a gas production operation, it may apply to MMS for an allowance for those costs which shall be in addition to any other processing allowance to which the lessee is entitled pursuant to this section. Such an allowance may be granted only if the lessee can demonstrate that the costs are, by reference to standard industry condi-

tions and practice, extraordinary, unusual, or unconventional.

(ii) Prior MMS approval to continue an extraordinary processing cost allowance is not required. However, to retain the authority to deduct the allowance the lessee must report the deduction to MMS in a form and manner prescribed by MMS.

(e) If MMS determines that a lessee has improperly determined a processing allowance authorized by this subpart, then the lessee shall pay any additional royalties, plus interest determined in accordance with 30 C.F.R. 218.54, or shall be entitled to a credit, without interest.